

BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the Matter of:)	
)	Docket No. 09-IEP-1K
Preparation of the 2009)	
Integrated Energy Policy Report)	
<u>(2009 IEPR)</u>)	

JOINT COMMITTEE WORKSHOP ON TRANSPORTATION ENERGY
DEMAND AND FUEL INFRASTRUCTURE REQUIREMENTS

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, AUGUST 24, 2009

9:00 A.M.

Reported by:
Peter Petty CER**D-493

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

Kristy Chew, His Advisor

James D. Boyd, Vice Chair and Associate Member,
IEPR Committee; Presiding Member Transportation and
Fuels Committee

Kelly Birkinshaw, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead
Nick Janusch
Malachi Weng-Gutierrez
Gordon Schremp
James Page
Ryan Eggers
Lynette Green

ALSO PRESENT

Presenters

Joe Sparano, Western States Petroleum Association (WSPA)
Joel Velasco, UNICA
Matthew Tobin, Kinder Morgan
Rahul Iyer, Primafuel
Felix Oduyemi, Southern California Edison (SCE)

Public

John Braeutigan, Valero Energy
Michael Redeemer, Community Fuels
Bill Wason, Sustainable Bio-Brazil
Seth Jacobson, Study for Advanced Studies on Terrorism

Via WebEx

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1 P R O C E E D I N G S

2 AUGUST 24, 2009

9:11 a.m.

3 COMMISSIONER BYRON: Ms. Korosec?

4 MS. KOROSEC: Right. We are going to go ahead and
5 get started now. Good morning, everyone. I am Suzanne
6 Korosec and I lead the Unit that produces the Energy
7 Commission's Integrated Energy Policy Report, or IEPR.
8 Welcome to today's Joint Committee Workshop on
9 Transportation Fuel Forecasts and Analyses.

10 The purpose of today's workshop is to discuss the
11 Energy Commission Staff Draft Transportation Energy
12 Forecasts and get public input on the proposed forecasts and
13 our related policy concerns. The staff will provide an
14 overview of the framework that they used in their analysis
15 and present preliminary findings on expected fuel demand,
16 projections of fuel and crude oil imports, and the need for
17 transmission infrastructure. Our agenda today will begin
18 with a presentation by the staff on Transportation Economic
19 Trends and Projections; next, we will have a staff
20 presentation on the petroleum and fuel demand forecast,
21 followed by a presentation from Western States Petroleum
22 Association. We will then move to a staff presentation on
23 Renewable Fuels, including Standards, Supply and Demand
24 Projections, and Infrastructure, and then we will break for
25 lunch, resume after lunch with presentations by several

1 renewable fuels stakeholders. After that, the Energy
2 Commission staff will present their Petroleum Fuel Import
3 and Pipeline Export Forecasts, followed by the Crude Oil
4 Import Forecasts. And we will use the remaining workshop
5 time to hear public comments on the day's presentations and
6 discussions, and we hope to adjourn shortly before 5:00.

7 Just a few housekeeping items before I turn it
8 over to the staff to get us started. Restrooms are out in
9 the atrium through the double doors and to your left; there
10 is a snack room on the second floor at the top of the
11 stairs, under the white awning; and if there is an emergency
12 and we need to evacuate the building, please follow the
13 staff out of the building to the park that is diagonal to
14 the building, Roosevelt Park, and wait there for the all
15 clear signal.

16 Today's workshop is being broadcast through our
17 WebEx Conferencing System, parties need to be aware that we
18 are recording the workshop and we will make the recording
19 available on our Website within a few days of the workshop,
20 and we will also be posting a written transcript once that
21 becomes available, which is about two weeks after the date
22 of the workshop.

23 For presenters and commenters, please make sure to
24 speak directly into the microphones here at the podium when
25 you come up to speak, or presenters here at this podium, to

1 make sure that the people on WebEx can hear you speak. And
2 during the public comment period today, we will hear first
3 from those in the room, followed by those on the WebEx. For
4 parties in the room who want to make comments, it is very
5 helpful if you can give the Court Reporter your business
6 card when you come up to speak, so we make sure that your
7 name and affiliation are spelled correctly in our
8 transcript. We are also asking parties to submit written
9 comments, and those are due by 5:00 p.m. on September 4th.
10 The information from this workshop is going to feed into the
11 2009 IEPR, the first draft of which is expected to be
12 released at the end of September in preparation for a
13 hearing on the draft report that is scheduled for October
14 14th. So with that, I will turn it over to the Dais for
15 opening comments.

16 COMMISSIONER BYRON: Thank you, Ms. Korosec. Good
17 morning, everyone. Happy Monday morning to you, all of you
18 who got up to be here on a Monday morning at 9:00, thank you
19 very much. I am Commissioner Jeff Byron. I chair the
20 Commission's Integrated Energy Policy Report Committee, and
21 with me is my Co-Chair of that Committee, Commissioner Boyd,
22 Vice Chair Boyd, and all the way to my left is his advisor,
23 Kelly Birkinshaw. We are hopeful that others will be
24 joining us here at the Dais as the morning goes on. And I
25 would like to thank you for being here at this Joint

1 Committee Workshop, both the IEPR and the Transportation
2 Fuels Committee, of which Commissioner Boyd is the Chair.
3 Is that correct? Yes.

4 VICE CHAIR BOYD: Transportation and Fuels
5 Committee, but what the heck?

6 COMMISSIONER BYRON: Yes. So I am going to keep
7 my opening remarks very brief. This is one in a series of
8 IEPR workshops that we have been conducting for the last
9 number of months and I think we are getting near the end of
10 what I refer to as the IEPR Season. A lot of information
11 gathered by this Commission and we will produce before the
12 year is out a policy report for the State of California
13 around all the key energy issues that we face. I am
14 reminded that the Integrated Energy Policy Report is
15 extremely important to document. A lot of people read it,
16 pay attention to it, and also use it to write legislation.
17 Administrations come and go, legislators come and go, but
18 our policy report tends to be the bedrock, or the
19 foundation, for California's energy policy. And it has been
20 an extremely good document, and it is incumbent upon myself
21 and Vice Chair Boyd to keep the quality of that document up.

22 We are fortunate today, the Transportation Fuels
23 area is not my forte, we have a very full committee today,
24 but we are fortunate in that Commissioner Boyd has been
25 working in this area for a great deal of time, former

1 Executive Officer for the Air Resources Board, and a
2 Commissioner here at the California Energy Commission now
3 for about seven years. So, Commissioner Boyd, I am going to
4 turn to you and ask if you have any opening remarks for our
5 workshop today.

6 VICE CHAIR BOYD: Well, thank you for your kind
7 remarks. My welcome and thanks to all of you for being here
8 this morning, early on a Monday morning, as Commissioner
9 Byron indicated. And I guess after this Commission's third
10 four-day work week, three furlough Fridays having now
11 occurred, we get to work all five days this week. So maybe
12 we can get five days' worth of work done in five days
13 instead of in four, like in the past. But in any event, it
14 is a pleasure to be here. I really do look forward to the
15 2009 Integrated Energy Policy Report in total, but
16 particularly in this area of Transportation Fuels and what
17 have you. It should be a banner year for this subject. The
18 AB 32 and climate change drives everything anybody does, it
19 seems, these days, so that is a major consideration to this
20 agency in carrying out its responsibility in this arena, if
21 not all the energy areas. We, of course, have our State
22 Alternatives Fuel Plan that was provided by AB 1007, a few
23 years back, and we produced that plan for the State of
24 California, which addresses this agency's overriding
25 concerns for climate change, but in particular, energy

1 responsibilities and transportation fuels responsibilities.
2 Energy security, concern for the State of California drives
3 us to pursue energy security through energy diversity, and
4 that plan led to the passage of AB 118, which provided money
5 and provisions to create an investment plan for investing
6 that money in the subject areas of alternative fuels and
7 alternative vehicle technologies to use those fuels, and
8 that has been done, and that process of investing those
9 dollars has begun, and coincidentally and quite positively,
10 perhaps, the nation's economic stimulus program came along
11 at the time we were getting ready to invest our 118 dollars,
12 and so we have made a huge effort to leverage our dollars
13 with federal dollars, hopefully to the benefit of
14 Californians and California companies, and what have you.
15 And also, the activities we carry out -- and I expect the
16 2009 IEPR, in particular, to address -- is the taking of
17 other goals and objectives, our biofuels plan, part of the
18 overall bioenergy plan nests with our 1007 plan and our 118
19 dollars, and all of those activities, in turn, cascade up or
20 down to meet AB 32 objectives, and work coincident with the
21 Air Resources Board's efforts on Low Carbon Fuel Standards.
22 So, as I have said for a long time, everything interacts
23 these days, particularly when considering climate change.

24 I am looking forward to this IEPR and this day,
25 but this IEPR really providing action recommendations to

1 address all these goals and plans that I previously
2 referenced, and therefore look forward to testimony we hear
3 today, written testimony, and then what the staff will do
4 with that in the form of various solid recommendations for
5 how to address the many problems that they have identified
6 in the report, problems I presume we will be hearing about
7 from folks today, and even more so in writing in the future,
8 and problems that, besides just the statement that we have
9 gaps and deficiencies where I feel we are obliged to start
10 making some pretty strong recommendations of how to bridge
11 those gaps, and I think the 2009 IEPR is a premier year and
12 a golden opportunity to do just that. So, with that, I
13 thank you and look forward to today's presentations.

14 COMMISSIONER BYRON: Thank you, Commissioner.
15 Hopefully the Chairman, Chairman Douglas, who is also on the
16 Transportation Committee, will have an opportunity to join
17 us today and, of course, will probably stop between
18 presentations to give her an opportunity to speak. Ms.
19 Korosec, would you like to go ahead?

20 MS. KOROSEC: Yes, let's go ahead and get started.
21 Nick?

22 MR. JANUSCH: Good morning, Commissioners. Good
23 morning to distinguished guests. My name is Nick Janusch.
24 I work in the Fossil Fuels Office and this morning I will be
25 discussing the transportation and economic trends and

1 projections considered for transportation fuel demand
2 forecasts. Our energy demand forecasts for transportation,
3 they cover various sectors in which we use a portfolio of
4 models, and to give credit for where credit is due, I will
5 name the staff in response for each sector. So the light
6 duty vehicle fuel demand forecast, that was done by Malachi
7 Weng-Gutierrez, raise your hand if you want; the transit
8 fuel demand forecast was done by Laura Lawson; the aviation
9 fuel demand forecast, that was done by Bob McBride and
10 Gerald Zipay; the freight fuel demand forecast, that was
11 done by myself, Nick Janusch; and the off-road fuel demand
12 forecast was done by Ryan Eggers.

13 Here are the topics I will discuss, which will set
14 the stage today for the current economic uncertainties,
15 trends, and projections used and considered in our
16 forecasts. I will begin with the uncertainties. What are
17 the changes in the regulatory environment? For example, the
18 Low Carbon Fuel Standard aims to reduce harmful emissions
19 and the rules are to be fully enforced in 2012, and will
20 require all participants in the transportation fuels market
21 to reduce carbon intensity, measured by the sum of
22 greenhouse gas emissions in all stages of transportation
23 fuel production and consumption. So this will involve
24 different measures, including the greatly increased use in
25 alternatives to conventional petroleum fuel and vehicles.

1 Also, fuel price volatility, land use, and markets for
2 alternative vehicles and fuels are also some of the
3 uncertainties, what we considered for our forecasts.

4 Now I will begin discussing information and bid
5 trends of various transportation demand indicators, as well
6 as economic, demographic, and other variables that are used
7 as inputs in our models. And here in this figure, we see
8 historical and forecasted values of California non-farm
9 employment and California gross state product. The
10 projections used here are inputs in our models and the
11 inputs that drive the models. We can see in this graph the
12 impact of recession, see the dips in the red and the blue?
13 And also, according to Economy.com, Gross State Product is
14 projected to return to positive growth by 2010, pending the
15 recession. Also shown here is Gross State Product is
16 expected to outgrow in plant. Now, here, we compare the
17 projections used in the 2007 IEPR to the projections used
18 for the 2009 IEPR; obviously, a lot has changed since 2007.
19 And here the population number, right here on the red and
20 purple, this is from the Department of Finance, is the
21 population direction trend, as you see, nothing has changed.
22 But the orange and green lines, these are from Economy.com,
23 and I will begin with the top, the orange line, which shows
24 the percentage employed, or the employment ratio, and we see
25 a sharp decline in 2009, and moreover, with the green, we

1 see in-plant projections have been lowered, too. So this
2 is a reflection of the current recession.

3 Now, let's discuss particularly light-duty
4 vehicles. And before I get into that, vehicles are
5 classified by their gross vehicle weight ratings, and all
6 vehicles, 10,000 pounds or less, are classified as light-
7 duty vehicles, while the vehicles that are greater than
8 10,000 pounds, those are considered medium and heavy-duty
9 vehicles. So here is a great table that shows the light-
10 duty vehicles stocked by fuel type. And this data is from
11 the Department of Motor Vehicles Database, and it shows the
12 amount of registered, operational on-road light-duty
13 vehicles. And we see a large growth in alternative vehicles
14 compared to gasoline vehicles. And we see in the recent
15 years the hybrid population has really taken off. And we
16 also see a large population of flex fuel vehicles, but this
17 population is not indicative of non-gasoline consumption.
18 Feel free to ask questions while I am going through my
19 presentation.

20 All right, here are the percentage breakdowns of
21 new light-duty vehicles by quarter, from 2004 to 2008,
22 overlaid with the retail price of gasoline. Now, I want to
23 draw your attention to the last few quarters. As retail
24 fuel prices went up, the percentage of new small cars
25 increased significantly after a steady increase over time,

1 and this was all at the expense of the larger vehicles.

2 And this is indicative that consumers are preferring
3 smaller, more fuel efficient cars in response to the higher
4 fuel prices observed in 2008 and previous years.

5 Now, from light-duty vehicles, we are going to
6 talk about medium and heavy-duty vehicles. And as I
7 described before, medium and heavy-duty vehicles are
8 considered to weigh more than 10,000 pounds, or more, and
9 these vehicles are primarily used in the freight and transit
10 sectors. Here we have the total population and a
11 distribution of medium and heavy-duty vehicles by seven fuel
12 types, diesel, gasoline, electric, hybrids, natural gas
13 which uses CNG or Liquefied Natural Gas, LNG, and another
14 classification which use fuels such as Methanol, Hydrogen,
15 and Butane. In this figure, the percentage of gasoline
16 vehicles decreased from 52 percent in 2000 to 38 percent,
17 while diesel vehicles percentage has been increasing, and
18 they increased from 48 percent in 2000 to 60 percent in
19 2008, so you see for diesel the blue bars are increasing,
20 and the green have been decreasing. And I mention all these
21 alternatives fuels, but you can barely see them -- where are
22 the alternative fuels? And you see the sliver at the very
23 end, in 2008 the alternative vehicles made up 1.4 percent of
24 the medium and heavy-duty population, with CNG and LNG
25 combined having the largest share at 1 percent; however,

1 many of these natural gas vehicles are registered to the
2 Government, or transit districts, primarily for urban
3 transit use, and so we see that, with medium and heavy-duty
4 trucks with alternative fuels, it is mostly just down by
5 government purchases, rather than private purchases.

6 Now on to freight. For California, ports play a
7 very important role in the global economy. Many goods are
8 imported into the ports of California, which are Ports of
9 Oakland, Long Beach, and Los Angeles, and they have to be
10 transported by truck or rail, and I will show you that -- in
11 this figure, it is not a report, but this illustrates the
12 importance of California in the global economy. This figure
13 shows total container traits in the entire nation, and it
14 shows the percentage of the Ports of Oakland, Long Beach,
15 and Los Angeles, and we see that there is a steady increase
16 in the amount of million metric tons traded, and so we see
17 this increase over time, and then here in 2008, we see a
18 contraction. This is a reflection of the global economy
19 contracting. And so this is a source of uncertainty, of
20 where exactly is this trend going to go? Is it going to
21 increase? Is it going to level off? Or will it decrease?

22 Now we are looking at relativity. This table,
23 which shows data from the American Association of Railroads,
24 shows average weekly number of carloads and inter-mobile
25 units, and to the left we see the annual averages, and to

1 the right the weekly numbers for 2009, and you can see to
2 the right, it is significantly less than the annual averages
3 that were observed in prior years. And so we see that the
4 amount of rail activity has decreased significantly since
5 2006. And so this is also a reflection of the recession and
6 the demand for goods.

7 Now, on to trucking and trucking activity. This
8 shows the for-hire truck tonnage index, which is indexed to
9 the year 2000, and measures movement of cargo. The rapid
10 increase in diesel fuel prices in 2008 in conjunction with
11 the severe downturn in the economy significantly reduced
12 trucking activity, and you can see this with the deep
13 decline in the last few months.

14 Now moving right along to transit. Here, we see
15 the recent trends in unlinked transit ridership for
16 California, as reported by the Federal Transit
17 Administration. And you can see, barely, there has been an
18 increase in transit ridership, and this is a reflection of
19 the people responding to higher fuel prices; but more
20 specifically, this is 2008 data, and here is a table from
21 the American Public Transit Association, showing the
22 California cities with the highest transit growth rates, and
23 here Oakland had the top growth for 2008 of 16.1 percent, so
24 this sort of shows that people have shifted more towards
25 transit in response to the high fuel prices observed last

1 year. Now, here is a table of the results from the 2008
2 California Vehicle Survey. In that table, we see transit
3 use is highest in the San Francisco region, or transit
4 accessibility and population are high, while the rest of the
5 state region is lowest since population density and transit
6 accessibility is low. There are no significant differences
7 observed in miles traveled to work by household size,
8 however, households with two or three persons have the
9 highest rate of transit use. The number of vehicles in a
10 household has a strong relationship with both the vehicles
11 traveled to work and transit use. And vehicle ownership is
12 positively related to the mean miles traveled to work and
13 transit use decreases with increased number of vehicles
14 available to the household.

15 Finally, to the last factors covered in my
16 presentation, aviation. And airlines, last year, responded
17 to the jet fuel price increases through the reduction of
18 empty seats and number of flights. Also in response to
19 decreased demand, airlines have taken their least fuel
20 efficient aircraft out of service. And to further
21 illustrate this, this graph shows U.S. airline passenger and
22 claimants, and according to the U.S. Bureau of
23 Transportation Statistics, for the first four months of this
24 year, total passenger and claimants were down 9.1 percent
25 compared to the same period in 2008. You can see that with

1 the green line, compared to the red line here. And that
2 concludes my presentation, and if you have any questions,
3 please, here is my contact information and right now I will
4 respond to any questions you may have.

5 COMMISSIONER BYRON: Commissioner Boyd?

6 VICE CHAIR BOYD: Thank you, Nick. A couple of
7 observations and perhaps questions embodied. Your slide 8,
8 which is the light-duty vehicles stocked by fuel type shows
9 a tiny bit of growth in diesel light-duty, which although
10 that, as a fraction of the whole population, is almost
11 insignificant, but I note that just with a mild bit of
12 difference because there has been a lot of questions about
13 whether there would be any increased light-duty diesel
14 powered vehicle penetration. It is growing ever so
15 slightly. The more relevant, or the more significant
16 comment -- it may be relevant, too - is flex fuel, and I
17 would only note that, while this population continues to
18 grow, there is virtually no fueling infrastructure in
19 California, particularly, but basically nationwide other
20 than the Midwest, and no indications that there would be
21 much of a growth in fueling infrastructure, although we are
22 obviously going to try to incent that with our 118 program,
23 to some degree. There is another dilemma of all fuel
24 vehicles getting credits for various things for which there
25 just is not a fueling infrastructure and is a policy

1 problem. Your slide 9, which is new vehicles sold by body
2 type, which is indicative of the trend we were seeing as
3 gasoline prices went up, I would only note that the
4 statistics about Cash for Clunkers lately has certainly
5 turned that trend on its head with the people returning to
6 very large-bodied, you know, they traded an SUV in for an
7 SUV, or a truck for a truck, and gasoline being a tad
8 cheaper, people have reversed themselves somewhat, although
9 I guess today is the last day for that program, so maybe we
10 will see the last of that surge. But hopefully they get a
11 tad better gas mileage in the vehicles than have been turned
12 in. Slide 15, which talks about U.S. ports, and how it has
13 leveled off a little bit, do you know if California ports
14 exactly mirror that trend? This is not disaggregated, it is
15 aggregate for the whole country, and I was just wondering if
16 you had access to any information about Oakland and L.A.
17 Long Beach.

18 MR. JANUSCH: Yeah, we do have access, but I
19 cannot answer.

20 VICE CHAIR BOYD: But you do have the data. I
21 would be curious to see later on if California is reflecting
22 the trend. It probably is, but it would be interesting to
23 know that as we formulate comments to be included in the
24 IEPR this year. And the last comment is about transit, and
25 it is interesting to see the growth in transit, the growth

1 is for the most part a little higher in areas that have --
2 well, the Bay Area has got the best access to transit with
3 BART and pretty decent bus service. I am just wondering if,
4 in 2009, with the budget crunches, every government at all
5 levels has seen, and the fair box increases they have had to
6 employ, as well as the reductions in service, and I know it
7 is too early to know, but I will remain curious as to
8 whether transit manages to hang on to any kind of a growth
9 rate or whether, as has historically been the case, it slips
10 back because it gets punished at the fair box by the need to
11 increase the rates to stay somewhat solvent, and that
12 impacts the people who need the service the most. As I
13 said, those are more comments than questions. Thanks for
14 the information, it was quite interesting when I reviewed
15 it.

16 MR. JANUSCH: Thank you.

17 COMMISSIONER BYRON: Okay. Thank you, Nick.

18 MS. KOROSK: Next, we will hear from Malachi
19 Weng-Gutierrez.

20 MR. WENG-GUTIERREZ: Good morning, Commissioners,
21 Advisors. My name is Malachi Weng-Gutierrez. I work in the
22 Fuels and Transportation Division, and I will be talking
23 about the transportation fuel demand and historic and
24 forecasted values for California.

25 I am going to start off with a slide that just

1 shows the historic trend in gasoline demand. Since 1945,
2 or after World War II, we have had a fairly steady increase
3 in gasoline demand. It has on occasion slowed down and we
4 have had declines in demand, those have primarily been
5 paralleled by recessionary periods, and that is what this
6 slide shows, is that we have a long period of growth until
7 we hit a couple of early recessions in the early '70s and
8 the early '80s, and that is where we get these areas of
9 declining demand, but for the most part, we have a fairly
10 steady growth from 1945 to today. I am going to -- the
11 insert here is lined up so that the grey regions, which are
12 the recessionary periods, should correspond with the demand
13 numbers that are represented here in blue. And I know this
14 insert is fairly small, so my next slide is basically that
15 insert, so you can get a better picture. But, again, I just
16 wanted to highlight that the recessionary periods are those
17 periods which lead to declines in demand and generally we
18 have had pretty steady growth. This is, again, the insert
19 from a previous slide, it is basically an index of real
20 taxable sales of personal income per capita, referenced or
21 indexed to 1970, so you can get a sense of where we had peak
22 taxable sales, this only goes up to 2000, but in this time
23 frame, peak taxable sales in 1978 or 1979, and personal
24 income has been growing fairly steadily, but, again, in the
25 recessionary periods, you have a decline of real per capita

1 personal income.

2 The next slide is going to focus in on that, the
3 last portion of the first slide, so the last couple of
4 years. It is a floating average of the monthly consumption
5 in California, it is from DOE, it is a 12-month floating
6 average, and it shows that there has been a decline, and a
7 pretty substantial decline in the last year and a half, or
8 two and a half years. Of note, what I thought was
9 interesting in this is that the monthly percent change since
10 October of 2007 has been pretty much negative, consistently,
11 every month, except for one month in 2008. So that is
12 pretty significant. I think it is a fairly long trend and
13 it does pre-date the large drop that we had in the economic
14 crisis in the latter part of 2008.

15 Now I would like to overlay the prices with the
16 demand that we have been seeing. And so that the red and
17 yellow lines here are the actual retail prices, and then the
18 bar chart below is the consumption numbers in millions of
19 gallons per day. On the left, again, is the annual average
20 consumption, and then on the right in green are the 2008-
21 2009 numbers for consumption. And as you will notice, as
22 the fuel price increased for gasoline, there was a decline
23 in the annual average consumption noted by the red bars. In
24 2008 and 2009, there has been a fairly -- it is much lower -
25 - or, it is lower than the annual average in the previous

1 years. And it is reacting to the price, as well. So you
2 see that, with the increase in price through July of 2008,
3 there is a decline in consumption, and then it pretty much
4 remains that way, although we had a decline in fuel prices
5 in the latter part of 2008. The recovery of demand has not
6 been there, but that primarily may be caused by, again, the
7 economic downturn that we are seeing recently.

8 So what I want to do is take a look at how
9 gasoline consumption was occurring on a per capita basis. I
10 thought that might be a better representation of how we are
11 consuming transportation energy, and so that is what this
12 is. It is a representation of per capita demand on an
13 annual basis from 2000 to 2008, and it peaked in 2002, and
14 has been fairly steadily declining since then. The axis on
15 the left here is obviously starting at 380, so it is
16 emphasizing the decline, but there is a decline and it
17 amounts to about 8 percent over this period of time. Now,
18 most of that, about 5.8 percent of that, is from the last
19 year, 2007 to 2008, and I anticipate we will continue to see
20 the downward trend this year in consumption. Again, I think
21 when I looked at the per capita number often people talk
22 about for per capita demand, I did not necessarily think
23 that that was representative of actual demand, or how much
24 we were traveling on the road, so I wanted to take a look
25 at, on a per vehicle basis, on a per driver basis, our

1 demand habits in this period of time, how they changed.

2 And that is what this next slide is. If you look at the

3 annual green or teal colored line, there is a downward

4 trend, as well, and this is the annual per vehicle demand

5 number. And it is a fairly decent decline; the thing that

6 made me suspicious about it was that it was not necessarily

7 due to a decline in -- it was due to two things, a decline

8 in consumption, certainly, but there was definitely a growth

9 in vehicles registered in California. And throughout this

10 period, you actually see an increase in the number of

11 vehicles per person in California, which is fairly

12 significant. So it grew from about 1.05 vehicles to about

13 1.2 vehicles per person in California. So, while it does

14 not sound significant, it does lead to a fairly significant

15 decline here on a per vehicle basis. But I thought maybe a

16 better representation would be how many drivers we have in

17 California, and are they still consuming the same amount of

18 energy that they consumed in the past. And that is what

19 this dark blue number is. And of the three kinds of numbers

20 that I looked at, per vehicle, per capita, and per driver,

21 this is the flattest. It only has about a 2.5 percent drop

22 over this timeframe, whereas -- well, up until 2007 --

23 whereas the others are dropping, again, as I said, 8 percent

24 and 11.7 percent for the per vehicle demand drop.

25 VICE CHAIR BOYD: Malachi, before you move on, I

1 have held this question through the last four slides, which
2 are all showing this somewhat downward trend in the various
3 different statistics you used to illustrate this, and we
4 tied it -- well, it has been stated it is tied to perhaps
5 the price of fuel and people's individual demand, but can
6 you just aggregate this in any way to improvements in fuel
7 economy of vehicles? Has there been a recognizable
8 efficiency improvement, i.e., fuel economy improvement, in
9 these vehicles, as well?

10 MR. WENG-GUTIERREZ: Sure, that is a good
11 question.

12 VICE CHAIR BOYD: I only ask good questions.
13 Thank you.

14 MR. WENG-GUTIERREZ: Right. Well, certainly that
15 would be another indication of why this would be dropping,
16 and that potentially is partially influencing it, but,
17 again, because of the timeframe with which the fleet turns
18 over, as Nick's slide that showed the vehicle population, we
19 are seeing increases in alternative fuel vehicles, and
20 certainly hybrid vehicles are coming into the marketplace at
21 a fairly quick pace, but for it to really influence our
22 overall demand, it is going to take a little while for that
23 to occur. So I would have to say that that probably has not
24 led to a significant -- that does not represent a
25 significant portion of the decline that we are seeing. Most

1 of it would be economic.

2 VICE CHAIR BOYD: Thank you.

3 MR. WENG-GUTIERREZ: So taking a look at the
4 diesel numbers, very similar to the gasoline number with the
5 overlaid prices, the historic numbers, we are not seeing
6 such a large contrast between the historic demand, which is
7 the annual average, on the left, and then the numbers in
8 2008 and 2009. Even with the increases in prices for the
9 first four years here that are representative of 2004
10 through 2007, we are still seeing an increase in demand for
11 diesel, whereas, in gasoline, we saw a decline. And then in
12 2008 and 2009, these monthly numbers, you are seeing numbers
13 that are certainly lower than historic numbers, but
14 certainly not as drastically lower as was represented in the
15 gasoline numbers. So I think this indicates the
16 responsiveness of diesel demand is not necessarily
17 correlated as well with prices, and I think that is
18 reasonable given that economic, industrial sector,
19 commercial activity, is the primary driver for diesel
20 consumption. So it is not until the 2008, November of 2008
21 through March of 2009, that you get something that is fairly
22 low in demand. And that really is more a reflection of the
23 downturn in the economy and the impact that it is having on
24 consumption.

25 And this is just a bar chart of jet fuel, one of

1 the other fuels that we look at. It looks fairly flat
2 here, but certainly in the last, between 2007 and 2008,
3 there was a decline of about 8.9 percent, a fairly
4 significant decline, and again, I think Nick touched on why
5 that is occurring, you know, the economic conditions are
6 such that the commercial airlines are having to put more
7 people in less planes and to try to conserve and try to
8 maintain their business models while prices are so high and
9 the economy is so bad. I think that is a reasonable trend.
10 The interesting thing will be to see whether or not it
11 continues. And I will get to that in the forecast numbers.

12 COMMISSIONER BYRON: Excuse me.

13 MR. WENG-GUTIERREZ: Sure.

14 COMMISSIONER BYRON: Mr. Gutierrez, I -- this is a
15 lack of knowledge on my part, I think, when I ask a question
16 like this, but of course, this is California commercial jet
17 fuel, and if costs are higher, of course, because of the
18 mobility of jet aircraft, could there also be declines as a
19 result of now taking on fuel in other states? Would we be
20 able to pick that sort of thing up?

21 MR. WENG-GUTIERREZ: I think they could make that
22 choice. I do not know if there is a large variability on
23 the price of jet fuel across the states, but that could
24 certainly influence the numbers, and that would be true of,
25 say, freight, as well, and anything where you have cross-

1 state travel, if prices are lower in other states, it could
2 potentially influence it. Gordon, did you have a comment?

3 MR. SCHREMP: Yeah, Gordon Schremp, Energy
4 Commission staff. I just wanted to add to that, that
5 airlines in their fueling behavior usually load enough fuel
6 to make the destination with an additional amount of fuel
7 for loitering time in the area. On rare occasions, you will
8 see an airport that may be without adequate supply of fuel,
9 like McCarron Airport in Las Vegas, and a plane will fly in
10 with enough fuel to get to Las Vegas, and then continue on
11 to Phoenix, but that is very rare. Airlines are usually
12 fueling in a safe manner at each point to get to the next
13 leg in their destination, and so we do not really see these
14 kinds of over-fueling or under-fueling in response to
15 differences in price; but, as Malachi points out, if you
16 look at the regional price differences in jet fuel, they are
17 remarkably similar. It is a very fungible commodity in the
18 United States and globally.

19 COMMISSIONER BYRON: Thank you.

20 MR. WENG-GUTIERREZ: So now I am going to discuss
21 the models and urgently discuss the models, really, just to
22 show these -- discuss these points. Really, what I want to
23 focus in on is the CalCARS model, or the light-duty demand
24 forecast and the methods used for that forecast. As in
25 previous forecasts, we base our forecasts on the economic

1 models. For the light-duty sector, we have in the past
2 used CalCARS and this time around we used a modified low
3 demand case modified by the current economic conditions.
4 For freight, we used the freight model, which Nick is the
5 one who operates, and we updated that with all the economic
6 growth indicators for the industrial sectors that we
7 evaluate. For trends that we updated with new economic and
8 demographic information, as well as inserting additional
9 trends and agency information, we go out with a survey to
10 collect data from trends agencies in California. We use all
11 of that information to then model transit demand to
12 California. And probably the one model that was changed
13 most significantly was the aviation model, this time around,
14 it basically got a new specification, as well as getting
15 updated with the economic and demographic data that we used
16 for the forecast.

17 So what I am going to present in the coming slides
18 will be a draft version of our gasoline demand. What I want
19 to highlight is the light-duty gasoline and diesel forecast
20 method. For 2007 and 2008, we basically used historic sales
21 numbers, so those are actual numbers that we used from DOE,
22 adjusting for certain -- we had to adjust for certain audits
23 and things like that. So we are pretty comfortable with
24 those numbers, those are actual. In 2009, what we did was
25 we used two sets of numbers for our high and our low demand

1 case. And what we did was we used an estimate of decline
2 from a 2008 number as the basis of our 2009 number, and so,
3 for the high case, we used the 12-month average drop, and
4 then for our low demand case, we used the current year
5 percent drop in demand. So for gasoline, we had, say, four
6 months of actual data from DOE, that decline was four and a
7 half percent, and that was what we used, then, as our
8 starting point for the 2009 number for the low demand case.
9 I do not know if that makes sense, but basically we used two
10 different projections of decline from 2008 as the starting
11 point for our 2009 number -- for our two different cases.
12 So we came up with those numbers, the high and low demand
13 case numbers, based on these declines, and then what we did
14 was we used the annual average growth rates that were
15 defined in the 2007 low demand case to pivot off of those
16 numbers, so basically we used the growth rates from that
17 2007 low demand case, and grew from the two points that we
18 had defined for 2009. And we chose that number, or that
19 demand case, because we felt it best represented the current
20 prices, as well as the current policy case -- policy
21 environment -- today. So that was the starting point for
22 the 2010 through 2030 numbers. That allowed us to develop a
23 reference case, which I will show you. This is a reference
24 case that was developed using that method, and then we
25 decided what we wanted to do was represent a band of

1 possible demand around this reference case. And so, for
2 the gasoline forecast, we used a 15 percent band around this
3 reference case, phased in over eight years, and that is what
4 this final slide is. So if you see here that the dash line
5 is the reference case, which is what I described, the
6 starting point being at that calculated number, and then the
7 annual growth rate from the 2007 number is what defines the
8 shape of that, and then we use this 15 percent variation
9 around that band, phased in over that eight-year period, to
10 get the two demand cases, the high and the low. And these
11 are the numbers that resulted from that analysis. And they
12 are fairly significant. The low demand case, there is a
13 drop of about 33 percent in demand, and that is very
14 significant. And I think the thing that is interesting
15 about these two numbers, or the two series of numbers, is
16 that, in the early part of the low demand case, you are
17 getting fairly significant drops. So by 2015, or in 2015,
18 you have this 13.25 percent drop in demand, whereas in the
19 high demand case, you are actually getting a growth, so
20 again, that could potentially be attributed to policies such
21 as Pavley, Pavley 2, other things in the short term
22 influencing these demand numbers, continued high
23 unemployment, certainly for the long-term, I think we are
24 seeing that employment is going to be an issue in
25 California. We will probably have higher unemployment than

1 we have in not the recent past, but in the early part of
2 2001-2002 timeframe. We had fairly decent unemployment. I
3 think the forecast that we are looking at is anticipating
4 higher unemployment in that timeframe. So again, I think
5 the interesting thing here is the short-term differences.
6 The long-term numbers are fairly similar in their growth
7 rates. And just also, the high number here is just -- is
8 about a 10 percent drop. So high demand case, 10 percent
9 drop; low demand case, 33 percent drop.

10 So what I shared before was just the light duty
11 portion and this is the total demand number aggregating the
12 medium and heavy duty demands, as well. And it does not
13 change that significantly, but it does get bumped up
14 slightly. The shapes are fairly similar to what was -- most
15 demand is light-duty. So adding the medium and heavy duty
16 gasoline demand does not significantly change those demands,
17 but it does raise it slightly. So the thing that I wanted
18 to emphasize on this slide is that these numbers are the
19 starting point for our analysis of the renewable fuel
20 standards, so these do not reflect compliance with RFS 2,
21 and do not necessarily reflect a lower demand which would
22 occur if we were to comply with RFS, which would mean that
23 we would have higher E85 numbers, that E85 would draw from
24 these gasoline numbers, and so our demand number for
25 gasoline would actually be lower than this -- in the case

1 where we are complying with RFS.

2 VICE CHAIR BOYD: Malachi, you referenced, of
3 course, the national RFS. What about any California goals,
4 objectives, and targets such as, well, have you attempted to
5 take into account what the Low Carbon Fuel Standard might
6 do? Have you included the biofuels targets that California
7 has set up for itself and our demands for electricity and
8 transportation fuel, electric cars, etc., so on and so
9 forth? Is that already factored into this?

10 MR. WENG-GUTIERREZ: Not explicitly. Again, I
11 followed the method, as I described, to come up with these
12 forecasts. It does not really take into consideration a
13 competitive alternative fuels market. That would be
14 something that we have done with the CalCARS model, had we
15 been able to do that. It would have shown how those
16 alternatives fuels would compete in the marketplace, and
17 what fraction of the transportation would be taken up by
18 those. And with LCSF, again, it is not really included in
19 this. I would say that Pavley is, Pavley 1 is included in
20 these numbers. Pavley 2 may be included in them, but we did
21 not specifically include them.

22 VICE CHAIR BOYD: It does not really exist yet,
23 right?

24 MR. WENG-GUTIERREZ: Right, well, but that is
25 true. I mean, there is talk of Pavley 3 and on and on and

1 on. But even so, you know, we did not model, say, the EISA
2 2007 fuel economy standard impact to demand. What we did
3 was we followed a method that I described, but we did not
4 insert, say, 35 mile per gallon by 2020 and see what the
5 demand ended up looking like, that was not something that we
6 did with these numbers.

7 VICE CHAIR BOYD: Thank you.

8 MR. WENG-GUTIERREZ: But there certainly are -- I
9 mean, given that this is a 33 percent drop in gasoline
10 demand, there have to be things that are influencing that
11 drop. I would anticipate things like, you know, LCSF, the
12 ZEV mandate, you know, Pavley 2 and up and beyond, you know,
13 carbon cap and trade, other -- AB 118 activities, AB 32
14 activities, would contribute to the decline in gasoline
15 demand, certainly in the low case. So -- but again, I think
16 what we were trying to do here is represent a band of
17 possible demand numbers, and I think that we are certainly
18 -- we would like comments on this to get a sense of if there
19 are things we need to include further, or if there are
20 certain things we have overlooked in this analysis. And
21 then, similarly, things like land use, smart land growth,
22 and things like that, we have not explicitly included those.
23 They could contribute to the decline that we are seeing in
24 this low demand case.

25 So these are the numbers for the overall demand

1 for gasoline. And, again, they are very similar to the
2 light-duty numbers, primarily because light-duty is most of
3 the market. But 33.5 percent hereon for the low demand
4 case, and a 10.4 percent drop over the 2007 to 2030
5 timeframe for the high demand case.

6 Now, this slide -- there have been a lot of
7 discussions internally about, well, the forecasts we were
8 putting together, and we wanted to contrast it with another
9 forecast that was out there, so we took a look at the EIA
10 demand forecasts and compared it with ours, and that is what
11 this is. And so the green numbers, or the teal numbers, are
12 the EIA numbers, and then the yellow, which I am hoping is
13 showing up appropriately here, are our numbers. And if you
14 notice, the high demand case for the Energy Commission is
15 falling between EIA's high and reference case, and the
16 numbers at the end here are the prices of the fuels, so this
17 is 213 cents per gallon in 2030, so it does make sense that
18 we would have a demand number that would fall between these
19 two numbers. Similarly, our reference case falls just below
20 their reference case. Again, that seems reasonable. And
21 then our final number, the low demand case, falls below
22 their low demand case. Now, although the prices here are
23 different, so that their low demand case has a fairly higher
24 price for fuel there, I think the regulatory and policy
25 conditions in California are certainly different than the

1 national policy conditions. So there are many things in
2 California that are pushing our demand probably lower than
3 what we would see in the national arena. Now, you know, if
4 other states adopt our policies, then maybe that would not
5 be true. Or, I could not say that, but I think that, for
6 the time being, it seems reasonable that we would have a
7 lower number than what might be observed in the national
8 arena.

9 So I am just going to proceed to the numbers
10 associated with the diesel demand. These are the numbers
11 presented in the report, again, short-term declines in
12 demand primarily due to economic conditions; in the long-
13 term, we see a return to growth as the economy recovers and
14 consumption begins to increase again. So goods movement is
15 one of the primary drivers here, and that is what we see as
16 recovering over the time frame of the forecast. In the low
17 demand case, we see about a seven percent increase in
18 demand, and then in the high demand case, we are seeing
19 about a 16.1 percent growth in demand. And this is a
20 representation of those numbers. Now, if you notice, there
21 is kind of a flat portion here, a flat period of 2015 to
22 2016, not quite sure what that is, but I think it has -- it
23 is referencing a number of the commodities that we have as
24 input. So there is a forecast, I looked at the two
25 different forecasts for transit and freight, and both have a

1 time period where there is a flattening of their demand.
2 Now, for transit, you do not see it significantly here
3 because, again, freight is the primary driver for that
4 diesel demand, but it does flatten out, as well. And it
5 flattens out a little bit later in this forecast. But the
6 2015-2016 flattening, I think, is primarily due to certain
7 commodities and their growth projections. Basically, those
8 are the inputs to the freight model, and that is what would
9 be causing that.

10 Finally, for jet fuel, we are seeing a substantial
11 growth in jet fuel, again, a recovery of the short term
12 downturn. We are thinking that demand for jet fuel is going
13 to increase fairly significantly. Over the forecast period,
14 jet fuel is increasing by 48 percent in the low demand case,
15 and upwards of 66 percent for the high demand case. And,
16 again, that is projecting a fairly healthy growth in that
17 sector. And there is a graph of the band around the jet
18 fuel demand. Now, these jet fuel numbers do not include
19 military demand, I believe, so there might be some
20 contribution to that, but for the most part, this is the Jet
21 Fuel A, which is a jet fuel that we are forecasting. So,
22 with that, if there are any questions, I would be happy to
23 address them. More comments or suggestions?

24 COMMISSIONER BYRON: No. Thank you very much.
25 Good presentation. I think we will press on.

1 MR. WENG-GUTIERREZ: Okay, great.

2 MS. KOROSK: Next, we will hear from Mr. Sparano
3 from Western States Petroleum Association.

4 COMMISSIONER BYRON: Mr. Sparano, I have not seen
5 you for a while and I know you do not believe me when I say
6 this, but I am always glad to see you and hear from you. I
7 always learn from you when you come present before this
8 Commission.

9 MR. SPARANO: Good morning, Commissioners, CEC
10 staff, and members of the audience. Very kind of you,
11 Commissioner Byron. I always enjoy being here, too,
12 particularly at the times where I am humbled into
13 remembering who I am and where I came from, which happens
14 often here, but today I might surprise you a little bit.
15 Let me state for the record, I am Joe Sparano. I am
16 President of the Western States Petroleum Association. I
17 want to share WSPA's views on this report with you today. I
18 have an overall observation, and that is I would like to
19 commend, compliment the CEC staff on a job well done. I
20 think you have prepared a credible and thorough forecast of
21 the state's transportation fuel requirements.

22 VICE CHAIR BOYD: Excuse me. Did I hear you
23 correctly?

24 MR. SPARANO: Someone out there, someone,
25 somewhere, will beep me up for having said that, but you

1 know what? Fair is fair. And so I think it is important -
2 -

3 VICE CHAIR BOYD: I wanted to make sure I heard
4 that correctly. Staff, you got compliments. Remember that.

5 MR. SPARANO: I have had less hard times when I
6 have not complimented the staff, so I may have to re-think
7 this.

8 I think the report does a really good job of
9 identifying many infrastructure, fuel, and supply chain
10 uncertainties and challenges that WSPA has, I hope, tried to
11 identify for you over the many years we have been working
12 together on IEPR's. We think that, although the report
13 contains some estimates on declining gasoline use that we
14 feel are overstated, so first response from the public to
15 what the two Commissioners were asking about in the two
16 previous presentations. I think the report does acknowledge
17 the important role that petroleum is going to play far out
18 into the future in California.

19 We had some basic messages back in April when I
20 stood here and I think they are pretty much unchanged, and
21 worth repeating. We are going to need all the fossil fuels
22 that we can get to meet U.S. and California energy demand
23 far into the future. Infrastructure capacity for liquid
24 fuels remains a capacity and will require expansion to meet
25 future demand. There is very little infrastructure in place

1 right now for alternative and renewable fuels and it will
2 be those elements of infrastructure that will be required to
3 bring in, as yet, not commercialized renewable and
4 alternative fuels to California market. The future is going
5 to require multiple sources of energy supplies to meet
6 demand, and that would include expanded access to off-shore
7 California and federal energy resources. And, finally, the
8 question remains, who is going to develop and pay for all of
9 the investments necessary to bring those renewable and
10 alternative fuels to market, for example, the low carbon
11 fuels mandated by the LCFS regulation that was adopted in
12 April 2009.

13 I do have a recommendation that I want to share
14 before going on, and that is WSPA recommends that staff in
15 each ensuing IEPR go back to the previous IEPR forecast of
16 demand, supply, and future development, and analyze how
17 accurate prior analyses were, so that the quality of each
18 future IEPR would be enhanced and improved, and at least
19 informed by that check of what has been forecasted
20 previously.

21 I love this artwork. I am not sure if it makes
22 any sense at all with respect to what we are talking about,
23 but I like it, so it is here. For those of you who do not
24 know, this is *The Scream*, by Edvard Munch, and it
25 illustrates, I think, a key issue in the energy policy

1 debate, and while many have postulated that the world is
2 running out of oil, and quickly, I think that is a notion
3 that has been asserted four or five times this century and,
4 in every case, technology improvements have been the
5 equalizer. And our industry has worked hard and been
6 successful around the world in finding and producing more
7 and more oil. So there are lots of opinions and lots of
8 facts that surround this issue, but I think we are not
9 running out of oil any time soon. But the notion of the end
10 of oil, or peak oil, I think, has helped drive policy that
11 calls for the reduction, or even elimination, of petroleum.
12 And we think more balanced policy initiatives are required
13 and would serve all of us better.

14 We have expressed some core concerns that we think
15 are now reflected in the staff report. They include the
16 issue with the existing petroleum infrastructure that it is
17 constrained in capacity, and that presents a real and
18 present danger to a reliable and stable future supply of
19 transportation fuels. There is a lack of attention, we
20 think, being given to the complex intersection of the
21 federal RFS 2 mandate, as well as the LCFS and other
22 programs. This is a very complicated area, as I think was
23 evidenced by a couple of the questions that were already
24 asked in the first two staff reports. And California has
25 had and delivered for a long time on its desire to show

1 leadership in the area of climate change policies, in
2 fostering an environment in which hope and optimism,
3 unfortunately, in our view, are replacing realism and sound
4 energy policy. So that is something to look out for. For
5 example, as to forecast document notes, policies dictating
6 renewable fuel usage are not aligned with the availability
7 of those fuels, the vehicles in place to use them, or the
8 infrastructure necessary to deliver those fuels to market.
9 And 22 years from now, or 21 years from now in 2030, that
10 may work itself out, but right now I do not see any specific
11 policies, and certainly no hardware in the ground that would
12 make me feel more comfortable about that situation.

13 We do agree with the report's observations about
14 the lack of integration of fuel with vehicles and consumer
15 elements of the transportation equation, and that is
16 something that is going to have to be solved. In addition,
17 we are concerned about the newly adopted LCFS, which will
18 require compliance with a program that is not achievable
19 with today's technology and fuel portfolio, and that will
20 require extremely costly innovation. It is not something we
21 can just wave our hands at. It is ironic, additionally,
22 that the LCFS may have the unintended consequence of
23 advantaging non-domestic fuels, like Brazilian sugar-based
24 Ethanol, rather than domestic fuels to replace non-domestic
25 crude oil and other fuels. I think what we are all looking

1 for is some opportunity to have more and more domestic fuel
2 supplies enter our fuel supply portfolio.

3 Finally, on this slide, we are particularly
4 gratified that the Energy Commission has recognized the
5 wealth of opportunities California has to improve our energy
6 supply security by expanding the development of oil and
7 natural gas reserves off the California coast. Let's look
8 quickly at some specific U.S. domestic energy supply issues.
9 I have used this slide before, I will not spend a lot of
10 time on it, it shows very clearly the vast amount of oil and
11 natural gas described as undiscovered technically
12 recoverable, and that means with today's technology, crude
13 oil and natural gas off both coasts in the Gulf of Mexico
14 and on and offshore in Alaska. Looking just at the Pacific
15 offshore, which clearly is of greatest interest to
16 California citizens and consumers and policymakers, that is
17 a 20-year-old estimate. On the one hand, it is probably
18 better than a lot of areas because we have been drilling out
19 there for over 40 years, drilling has continued right up
20 through today, pretty abundant offshore operation producing
21 around 100,000 barrels a day of our 650,000 barrels a day
22 California production. But those numbers, 10.5 billion
23 barrels of oil, 18 trillion cubic feet of natural gas, the
24 equivalent is two to three more billion barrels of oil, the
25 oil by itself, if we could produce it at the same rate as

1 today's foreign imports, which at the end of 2008, the CEC
2 identified as about 850,000 barrels a day, or 48.5 percent
3 of all the crude we put in California refineries, if we
4 could produce that offshore resource at the same rate, we
5 could eliminate foreign imports for over 30 years. Now, no
6 one is saying today that we can run and produce at that
7 rate. It will certainly take time if we are allowed to
8 drill offshore to ramp up, but I think the figures are
9 illustrative of great opportunity that sits there offshore.
10 And if you are looking at issues about the end of oil, there
11 is even more vast quantities of oil in Canada, and around
12 the world, according to lots of sources. But right now, we
13 should be concerned about policies that affect our situation
14 and, in particular, the offshore supplies off the coast of
15 California.

16 The MMS has been very vocal and straightforward,
17 Minerals Management Service of the Department of Interior,
18 in describing the record of this industry in its activity
19 offshore, and certainly there is a lot of interest, a lot of
20 emotion that surrounds offshore California drilling, almost
21 all of it precipitated by the tragic and terrible spill in
22 1969 in the Santa Barbara Channel. Since then, in 40 years,
23 the industry has produced a billion barrels of oil offshore
24 California, spilled 850 barrels that you can see, according
25 to this report. I can assure you that it is 850 barrels too

1 many. I have been in this industry 40 years and I know how
2 I feel, and how my associates feel. We all get up every day
3 with a target of no spills anywhere -- ever. It is a
4 daunting challenge to meet that objective, but that is where
5 it starts, and I think this record, as shown by the MMS,
6 illustrates that there has been a good degree of success in
7 this area. I think bringing these offshore resources to
8 market will have a beneficial effect on consumers and
9 businesses. It will provide much needed long-term stability
10 to transportation fuel markets. I mentioned earlier,
11 California currently imports almost 50 percent of the oil we
12 use to make products from foreign sources. We import
13 another 13 percent, according to this agency, from Alaska.
14 Sixty-two percent of everything we use shows up here by
15 tanker. And that is a number that is only going to get
16 bigger as California production decline continues. And so
17 we need to augment existing production.

18 There are some other benefits that accrue from
19 additional offshore drilling, the numbers that I am going to
20 give you next are from a study by ICF International about
21 the MMS five-year plan that is currently under evaluation by
22 the Department of Interior. These numbers relate
23 specifically to California, they relate to the 2030
24 timeframe. The benefits of accessing offshore resources
25 include more than 14,000 new jobs in California, \$3 billion

1 estimated new economic output, and over \$12 billion in new
2 government revenue, and that is for state and local, county,
3 city revenue needs and needs to fund services. And those
4 are real dollars, they are not new taxes. They are dollars
5 that accrue from the act of producing and the revenue
6 sharing the rents that are paid on leases, the bid bonuses,
7 and then the ongoing revenues from royalties, as these
8 barrels are produced.

9 Let's take a look at some of the technology
10 involved here. This is a quick picture of what is called
11 Extended Reach Drilling. Extended Reach Drilling has
12 already been proven worldwide and even in California in some
13 areas to be useful, and safe, and environmentally sensitive
14 out to anywhere between three and seven miles from the drill
15 site. Why is this important? Well, if you want to drill
16 offshore California, there are some areas where you can site
17 a drill operation on land and drill out into the reservoir.
18 That is what this picture shows. And it is an important
19 facet of our technology improvement that I think is critical
20 for California policymakers and consumers, citizens, to
21 understand.

22 While we are on this slide, I want to just depart
23 a second and talk about some specific issues with the IEPR
24 document, and they relate directly to the questions that
25 Commissioner Byron and Commissioner Boyd were asking during

1 the staff presentations. You have a very very strong
2 reduction in gasoline consumption, I think more than 33
3 percent by 2030. The State Department of Finance has
4 identified that our population is likely to grow during the
5 same timeframe by more than 30 percent from 37 million
6 citizens now to close to 50 million by 2030. And looking at
7 the low demand scenario, that implies, calculates out to,
8 but I guess "implies" is still a fair word, a per capita
9 drop from over 400 gallons per capita down to about 200
10 gallons per capita. It just seems to us like an awful lot
11 and maybe an area you want to go back and take another look
12 at how credible that may be. That is a lot less driving for
13 a lot more people. So I think it is something that requires
14 further examination.

15 Here is another look at technology and this
16 happens to be Extended Reach Drilling that starts on an
17 existing offshore platform, or it could be a new one, but in
18 California's case, we have 27 platforms currently in
19 operation off the coast, 22 in federal waters, five in state
20 waters, we have five drilling islands. Certainly, the
21 platforms that are operating today present an opportunity,
22 if and when the MMS five-year plan is approved, to reach
23 from those existing platforms, either back into state
24 waters, or out into federal waters where there is
25 considerably more oil and gas, at least by the MMS

1 estimates.

2 I mentioned earlier that we are encouraged by the
3 report's recognition of the potential for developing
4 California's offshore resources. I want to quote the report
5 on page 21 because there are a couple observations I have
6 about this next statement. The report says, "The continued
7 decline of California crude oil production could be reversed
8 through increase exploration and drilling in state and
9 federal waters, but any appreciable impact on the level of
10 imported oil would be at least a decade away." Well, we do
11 not claim that our abundant offshore energy resources can be
12 produced overnight, however, as I have said on many
13 occasions before, California is probably in the unique
14 position versus the rest of the country to bring those
15 resources that exist offshore and which we are not currently
16 allowed to access, bring those to market a lot faster than
17 many other areas. There are several projects already
18 awaiting approval, review and approval, that could bring
19 offshore California oil online and to market way before the
20 ten-year time period indicated in the report, and help us
21 reduce our dependence on imports. The staff report also
22 states that expanded offshore development would require, and
23 I will quote, "new infrastructure of offshore oil production
24 platforms, interconnecting pipelines, crude oil trunk lines,
25 and pump stations." Several of the offshore and onshore

1 projects that have been proposed will utilize existing
2 infrastructure along with advanced technology and state-of-
3 the-art techniques, such as Extended Reach Drilling. That
4 will allow us to access new oil and gas supplies and bring
5 them to market safely and with environmental sensitivity
6 long before 10 years are out, and with, in many cases,
7 existing infrastructure. That is not to say that, if we are
8 allowed offshore, and we have a lot more opportunity, that
9 there would not be some new platforms and more lines, trunk
10 lines, and facilities onshore. I do not know that at this
11 point. But we certainly have the means with existing
12 facilities to do a lot of producing in a timeframe that is
13 measured in a couple of years or more, rather than a decade
14 or more, and that can only help us with respect to our
15 current high amount of foreign imports, and we become more
16 and more vulnerable every day as those imports increase.

17 This is another unusual cartoon, again, I like it,
18 so we use it from time to time, and it reflects the notion
19 that all we have to do to get rid of our addiction to oil is
20 just move to alternative and renewable energy, and that will
21 be accomplished relatively easily. And I think renewable
22 energy supplies, even with huge huge projected growth rates
23 in the EIA forecasts that were mentioned earlier, are going
24 to take decades before they gain substantial market share,
25 and the EIA in a chart that I will show you in a minute,

1 paints a very different picture than just switching from
2 oil to all kinds of renewables, and being happily on our way
3 into a different future. That may in fact be our future
4 many years out. But it is not around the corner and I think
5 there is an element of realism that we have to inject into
6 our policy debates. EIA has already reduced their forecast
7 twice this year, their annual energy outlook. But still, it
8 anticipates nothing like the drop in demand for gasoline
9 that is suggested in the staff report. The EIA report shows
10 that, despite huge increases in biomass and other renewables
11 between 2007 and 2030, by 2030, fossil fuels, oil and gas,
12 and coal, will still make up 78 percent of the supplies to
13 meet forecasted demand, 22 percent for biomass and
14 renewables, plus nuclear, plus hydro. And I will show you
15 that on the next slide. But just one more point here about
16 alternative energy. Whether there are additional imports of
17 foreign energy supplies, or other U.S. crudes, or whether
18 there are new renewable and alternative fuels that are
19 developed consistent with this plan and with other state
20 plans, all of those new fuels will require infrastructure.
21 Right now, we can get Ethanol here by rail car, we can get
22 it here by barge, and a lot of good work in the staff report
23 identifying some of the challenges that may occur if those
24 Ethanol delivery systems no longer will carry the corn-based
25 Ethanol, rather other types of Ethanol -- cellulosic,

1 Brazilian Ethanol based on sugarcane, they may require some
2 dramatically different applications and certainly more
3 hardware on the ground. So that is going to take more
4 permitting, it is going to face the same permitting and
5 community challenges that conventional energy has faced, and
6 it is still going to need huge amounts of investment
7 capital. So those are some things I would like the staff
8 and the Commission to think of as you go forward.

9 This is the EIA chart. I will not spend much time
10 on it, but look on the right-hand side, your right, my
11 right, that is the breakdown, still 55 percent oil and gas,
12 almost 11 percent from biomass and renewables, it is a huge
13 105 percent growth from the 2007 amount of those fuels, but
14 still 11 percent of the total. Nuclear is flat, hydro is
15 flat, altogether they make up about 22 percent. So I call
16 on this when I use it in other areas just for a reality
17 check. This is a hard reality from EIA. And, as I have
18 said, they have already trimmed this forecast twice to
19 reflect economic downturn and changes in demand that have
20 occurred this year for petroleum and other products.

21 I have used this chart before and I will not spend
22 a lot of time on it. The main point here is, in our
23 existing system there are no pipelines that bring crude or
24 products into California, none. You can see where the major
25 refining centers are in this country, mostly in the Gulf

1 Coast, but also here in California and in Washington,
2 replacing supplies that are missing for whatever reason is
3 an arduous task and can require 10-40 days, depending on
4 where you have to get that supply. There is no reason to
5 think that infrastructure for renewable fuels and
6 alternatives will face any less daunting challenge, and many
7 of the renewables that are looked at today as fuels of the
8 future that will replace or augment petroleum still have to
9 start their long trip to have infrastructure in place in
10 California that will satisfy our needs and carry the volume
11 of fuels that are going to be necessary to make a market
12 penetration into California's fuel supply portfolio.

13 What does that all mean? Well, a lot of people
14 last year carried the mantra of "Drill, Baby, Drill," since
15 I have been here in Sacramento, I have heard the opposite
16 many times, which is don't drill anywhere or building
17 anything -- ever -- if it happens to be petroleum-based.
18 And I think those are two extremes and we will be well-
19 served by finding ourselves and putting ourselves through
20 policy decisions somewhere closer to the middle of that.
21 And even though demand has dropped, we still do not have
22 very good energy security in California. I mentioned the
23 numbers in the U.S. and we are already at 60-65 percent of
24 foreign imports for every single drop of crude and products
25 we use in America every day -- 60-65 percent, it is not

1 getting better. It will only get better through the
2 combination of more domestic supplies and alternatives and
3 renewables working their way into the marketplace.

4 So what do we do? We think the policy options
5 include some balance, certainly additional domestic supplies
6 through greater access, conserving energy, we all can do
7 that every day with how we use energy as individuals, better
8 efficiency, industry has an obligation and an opportunity
9 from an economic standpoint to do a better job of being more
10 efficient in how we operate, and finally, developing
11 alternative and renewable fuels and technologies of all
12 sorts. The next generation Ethanol, biodiesel, other
13 biomass fuels, solar, wind, hydrogen, electric battery
14 design. And then we should not forget nuclear applications
15 that create clean products from coal and oil sands in
16 Canada, and oil shale in the United States, both of those
17 last two have incredibly large volumes of reserves that are
18 available to come to market. They certainly each have their
19 technical challenges and greenhouse gas issues, but everyone
20 who is involved in both of those activities is sensitive to
21 and understands the need and requirement to deal with those
22 issues. And we certainly have an opportunity to create more
23 domestic supplies if we are able to bring those to market.

24 I have shown you this slide before. This is the
25 last one. Our industry, not surprisingly, thinks the path

1 to success starts with the existing cleaner burning supply
2 of petroleum. We have made it cleaner year after year and
3 will continue to do so. It certainly can and should be
4 augmented by all types of renewables and alternative fuels,
5 scientifically sound -- they have to work -- technologically
6 feasible, you have to be able to deliver them to market in
7 commercial quantities. It is one thing to drive a car from
8 North America to the tip of South America, as one fellow did
9 a couple years ago, and stopped at every McDonald's and
10 other fast food place, and take French fry oil and put it in
11 the tank, and power the car -- that is doable, it is just
12 not doable on a mass scale. So we have to get there, and
13 things have to be cost-effective. So balanced supply is the
14 key. And I think the more we concentrate on that, the
15 better off we will be.

16 So let me make a few closing comments. We
17 encourage the Commission to continue to identify the
18 benefits to California for increased access to energy
19 resources, particularly those on California's outer
20 Continental Shelf. In many respects, the only thing that
21 stands in the way of improved energy security for California
22 is an outdated political Orthodoxy. There is a lot of
23 politics in the area of offshore access. We think it is
24 time to re-think our policies and our politics with respect
25 to offshore access, and to bring what is truly a vast amount

1 of technically recoverable energy supplies off our coast
2 into California's energy supply portfolio. California
3 citizens and consumers who are currently hurting from high
4 unemployment and reduced services would be the beneficiaries
5 of more jobs, new revenues for state and local governments,
6 and greater energy supply security. Thank you for giving me
7 the opportunity to share WSPA's views with you this morning.
8 I would be happy to answer your questions.

9 VICE CHAIR BOYD: Well, thank you, Joe. You are
10 right, there was enlightenment in the presentation. Just a
11 comment, it is almost not a question. One of the dilemmas
12 with potential continued reliance on petroleum is, of
13 course, it is a fossil fuel, which you acknowledge, and the
14 global climate change concerns and programs do put pressure
15 on petroleum. The Low Carbon Fuel Standard proposal of the
16 state is not a proposal, as I understand it, to eliminate
17 petroleum, rather it recognizes that petroleum will be used
18 in the future. It appears to be an effort, you know, just
19 to reduce the carbon footprint of that petroleum. So
20 reduce, but maybe not eliminate, is something I see in the
21 many goals of California government. And the other thing
22 that you reference, too, is energy security, I mean, that in
23 eliminating foreign imports. You put all of those things
24 together and, as you acknowledge, there will be a role for
25 alternatives and these are the competing fuels that we have

1 to deal with. So I think you commendably recognize
2 conservation efficiency and the development of alternatives,
3 and I think actions the state is taking do acknowledge that,
4 like it or not, petroleum is going to be the dominant
5 transportation fuel for a long long time, for lots of the
6 reasons you indicate. But I do not see in some of us, you
7 know, a political desire to eliminate petroleum or even that
8 which is the reduction component, it is to address these
9 other issues. Fossil, you know, any fossil fuels are
10 problematic with regard to greenhouse gas issues, climate
11 change, and what have you, and that is what drives us to a
12 very large degree these days, so I see the paths melding
13 better than they have before. We still have our somewhat
14 different views on how fast we have to go places, but I did
15 not really have a question, it is more a statement, per
16 usual.

17 MR. SPARANO: Commissioner Boyd, thank you for the
18 statement. Certainly, the issue of greenhouse gas is one
19 which concerns us as an industry, as it does the rest of
20 California, the nation, and the world. One of the things
21 that we do believe will be very beneficial, I did not
22 mention it in the context of the discussion, but I will in
23 response to your observations. Carbon capture and
24 sequestration, or carbon capture and storage, is a really
25 important element that we need to ensure that policymakers

1 understand. This has been used for 50 years or so in this
2 industry, largely outside of California, but it presents a
3 great opportunity to use the carbon dioxide produced in
4 whatever situation, and put it down hole into an existing
5 petroleum operation, and help with enhanced oil recovery to
6 move out more oil from a reservoir, or simply stick it in a
7 reservoir that has been depleted, where it will stay for
8 eons. So that is one piece of the puzzle. The other I want
9 to mention, I think it cannot be understated, the Low Carbon
10 Fuel Standard, for all of its well intended policy
11 objectives, we are sitting today faced with a dilemma as an
12 industry of having no known pathways to beat the Low Carbon
13 Fuel Standard requirements, and, yes, it has been back-end
14 loaded, which is very fortunate for all of us, but there are
15 still lots of dilemmas and one that is very very important,
16 that people should understand, gasoline has a carbon
17 intensity of 96, corn-based Ethanol, according to many, and
18 I guess the important thing, according to the Air Resources
19 Board, when you use a full lifecycle analysis, it has a
20 carbon intensity of 96 and change. We are not going to be
21 able to use corn-based Ethanol to meet our 10 percent
22 reduction in intensity. Cellulosic Ethanol, as far as I
23 know, not only are there no plants operational, but there
24 are not any with steel in the ground because the process
25 still has not reached commercial availability. So those are

1 the kind of things that are going to challenge all of us to
2 try and meet these laudable objectives, and I just wanted to
3 mention those two since you gave me the opportunity.

4 VICE CHAIR BOYD: Well, just one last comment.
5 You hit the nail on the head, and I neglected to mention
6 lifecycle analysis, but that is going to be the decider for
7 many many things in the future, and whether or not that
8 gives advantages to the likes of Brazilian Ethanol versus
9 corn, or other alternatives, it will all come out in that
10 equation once those equations are thoroughly developed, and
11 that will give us our answers to a very large degree.

12 COMMISSIONER BYRON: Mr. Sparano, thank you. I am
13 glad you like certain aspects of the report. I wanted to
14 drill down on one of them a little bit more, that being the
15 staff conclusion that oil production could be reversed
16 through increased exploration and drilling. Do you agree
17 with the staff's numbers in the report with regard to the
18 number of barrels per day that could be increased with
19 offshore drilling?

20 MR. SPARANO: I do not know how to -- I have read
21 the numbers, I went through the report, the 28,000 or so at
22 the start from one project, 28,000 barrels a day, and I
23 think it was all the way up to 430 or 450,000 barrels a day
24 by 2030. Did I get that right?

25 COMMISSIONER BYRON: 480,000 barrels.

1 MR. SPARANO: 480,000 -- that is more than half
2 our current imports. I do not have the knowledge of how you
3 arrived at those numbers, but I think perhaps more
4 importantly than whether I agree with them or not, is how
5 substantial they are, and our ability through technology and
6 through the existing infrastructure to bring more of those
7 production barrels to market earlier will be key to helping
8 our energy security.

9 COMMISSIONER BYRON: It also stated in the report
10 that that would be about 10 years to get to -- well, let's
11 see if I --

12 MR. SPARANO: It said it could be a decade before
13 we see any of the production, and my observation was that
14 there are three or four projects already in place, ready to
15 go, that would bring more than a few 10,000 barrels a day to
16 market within a short period of time if and when we got
17 approval to access the reservoirs.

18 COMMISSIONER BYRON: Right. The report talks
19 about these having a personal impact would be at least a
20 decade away, and you indicated in your comments that there
21 were opportunities with minimal or no new infrastructure,
22 including possibly no new offshore oil production platforms,
23 pipelines, or trunk lines. So my question is, so you are
24 suggesting that we would be using existing infrastructure to
25 get access to some of these early opportunities?

1 MR. SPARANO: Right. There is a project that
2 everyone knows about because it is in the budget, called
3 "Tranquillon Ridge" that proposes to drill from an existing
4 operational platform in federal waters, back into state
5 reservoir, to bring oil to market through the existing
6 platform under sea line and oil processing plant. There is
7 a competing project onshore at Vandenberg Air Force Base
8 that would use the same Extended Reach Drilling technology
9 to accomplish the same goal. There is a third project
10 called "Paradon Project" by another of our members, three
11 different ones, that would produce from an existing platform
12 in state waters, from federal reservoirs. So those three
13 are all ready to go, they all use existing infrastructure,
14 putting the drill bit in the ground and accessing the
15 reservoirs, bringing the oil to market is only a function of
16 getting regulatory and legislative agreement to allow us to
17 go forward.

18 COMMISSIONER BYRON: Well, my question, where I
19 was headed on all of this, was your initial concern that you
20 brought up about the potential for any leaks. When you are
21 using infrastructure that could be 40, 50, 60 years old,
22 isn't that a concern?

23 MR. SPARANO: It is not a concern based on the
24 amount of aggressive regular constant diligent inspection by
25 MMS, and they are on those platforms every day, every week.

1 There has been a great deal of improvement in technology
2 and leak detection, as well as subsea valves, shut-off
3 valves that would have, in fact, stopped an event like the
4 Santa Barbara spill had that technology existed 40 years
5 ago, so that, Commissioner Byron, there is never any day we
6 get up where there is no risk, every day we get up, though,
7 we are doing everything we can to ensure that what is in
8 place is more than adequate, and that all the new
9 technologies that are available to us are being used.

10 COMMISSIONER BYRON: Good. Thank you. I see Mr.
11 Schremp has stepped forward. Perhaps he wants to add
12 something.

13 MR. SCHREMP: Thank you, Commissioner Byron.
14 Gordon Schremp, senior staff with the Energy Commission. To
15 shed a little light on those numbers that you are talking
16 about in the crude oil, those numbers are actually a
17 combination of federal data, as well as data by the
18 applicant for Tranquillon Ridge. The federal offshore
19 agricultural shelf numbers are from the DOE and SPR's
20 analysis of how fast and what quantity of crude oil could
21 come from Pacific waters and, arguably, the lion's share of
22 those reserves are off of California. So we have used those
23 numbers and we have used their timeframe of, you know,
24 likely a decade to get appreciable volumes, and that is
25 because of the very lengthy process, the five-year plan

1 development, as well as in subsequent bid process, and an
2 EIR and EIS process to even get the first offshore rates
3 going. The second source, as recently discussed, is from
4 existing facility Irene, offshore, Plains All-American has
5 published some numbers that they have forecast how much oil
6 and in what period of time that will become available, and
7 we have used their numbers as part of our report
8 development. So they are a combination of federal data and
9 applicant data for Tranquillon Ridge.

10 COMMISSIONER BYRON: Thank you. Mr. Sparano,
11 thank you. I was a little concerned in your presentation,
12 you know, when you started with *The Scream*, by Mr. Munch,
13 you know, that painting was stolen, at least one of them, in
14 2004. But fortunately it was recovered and so, therefore,
15 we will not be blaming the oil industry for that, as well.

16 MR. SPARANO: Thank you, Commissioner Byron, very
17 generous of you.

18 COMMISSIONER BYRON: But thank you very much for
19 being here and for your presentation.

20 MR. SPARANO: Thank you, sir.

21 MS. KOROSSEC: All right, next, we will hear from
22 Gordon Schremp from the CEC staff.

23 COMMISSIONER BYRON: Mr. Schremp, you go right
24 ahead because you have, I think, the record for what will be
25 the longest presentation during the IEPR season, and we are

1 a little bit ahead of schedule, but we are going to count
2 on you to finish in time for lunch.

3 MR. SCHREMP: Good because, now, you do have
4 seatbelts, right? I suggest you strap yourself in, I will
5 go at a fast pace, a brisk pace, but certainly any questions
6 anyone has, I would be happy to take those as I go through
7 because I will be covering a variety of topics within the
8 umbrella of renewable fuels, so I hope to shed some light on
9 some of the concerns that some of the previous speakers have
10 already noted, but also clarify some of the demand
11 projections that are in part certainly based on what Malachi
12 presented earlier, and how that will change.

13 So once again, Gordon Schremp, senior staff,
14 Energy Commission. No doubt, the amount of renewable fuels,
15 especially Ethanol, will dramatically increase in
16 California. California currently uses about a little --
17 almost 7 percent Ethanol in all its gasoline. We have a
18 little bit lower concentration than other places that do use
19 Ethanol, almost any other place in the United States that
20 has Ethanol is at about a 10 percent level, so we will soon
21 be there, we anticipate next year. I will talk a little bit
22 about that later.

23 So we have been looking at how much more renewable
24 fuel is going to be needed, when, what the infrastructure
25 impacts may be, and I think a lot of this is going to come

1 down to what we believe is a significant increase in the
2 amount of E85. The amount of Ethanol production in the
3 United States has increased rather dramatically, as this
4 slide indicates. Production through 2008 has reached a
5 level of 9.2, and this is not production capacity, it is
6 actual output, so over 9 billion gallons -- quite
7 remarkable. And in 2006, we became number 1 in the world
8 in terms of Ethanol production as a country, eclipsing that
9 of Brazil, and Brazil remains second place, and we will
10 share some of those figures a little bit later.

11 Well, along with the increased production in the
12 nation, we have seen a jump in California use of Ethanol and
13 we went along for a long period of time at less than 100
14 million gallons, but then there was a large jump in 2003,
15 and then, once again, in 2004. And that was because
16 Methyltertiarybutylether, another oxygenate choice at the
17 time, was ordered to be phased out of use in California by
18 the Governor. So once that was accomplished, the other
19 oxygenate that could be used was Ethanol, in fact, the only
20 one that is permissible to be used in California at this
21 time. Any other oxygenates must go through a full fate and
22 transport assessment for any potential deleterious impacts
23 on the environment, or citizens, for health. So at this
24 point, Ethanol is really the only option that can be used.
25 Now, recently California was granted the ability to not use

1 any oxygen in gasoline or an oxygenate from such things as
2 Ethanol, but that position is essentially moot because the
3 renewable fuels standard part two will dramatically increase
4 the requirements to use Ethanol. And so I will get into
5 that momentarily.

6 This federal standard, what we call RFS2, is a
7 revision that is currently out for comment. Those comments
8 are likely, I think, due in September and hopefully by the
9 end of this year we will see some decisions by USEPA on what
10 the final regulations may look like. Actual obligated
11 parties have a renewable -- what we call an RVO, or
12 Renewable Volume Obligation. It is a formula that EIA uses
13 -- excuse me, USEPA -- and there is a calculation of what
14 that number is. And then all the obligated parties figure
15 out sort of what my volume is, and then they have a company
16 pool members, company-wide, how they try to meet those
17 obligations, and they have renewable identification of RINs,
18 and these are basically a tracking mechanism, but probably
19 more importantly, it is a way of tracking over-use. So if
20 you use more than you have to by this federal mandate, you
21 can actually bank those credits for your own company use the
22 following year, a portion of those, or you can -- if you are
23 going to under-blend, and not meet on your own, you can buy
24 credits from those who have excess credits, and there are
25 aggregators of RIN credits. So this will have some

1 importance moving forward in terms of additional
2 flexibility, but certainly when we talk about E85. Now, I
3 want to stress, this is not a per gallon, that it is
4 monitored on a per gallon basis, you basically have company-
5 wide volumes to track your petroleum-based fuel quantities
6 in the gasoline and diesel arena, and then what volume of
7 renewable fuels during a period of time, and then what type
8 of renewable fuels because, like the Low Carbon Fuel
9 Standard, USEPA is also looking at different types of
10 renewable fuels and their carbon tests, so those would be
11 the advanced renewables such as Cellulosic Ethanol. These
12 are the numbers through 2022, beyond that date in our
13 analysis we assumed these numbers were flat, not changing,
14 we did not increase them, but it is likely that these
15 numbers will rise post-2022. But Congress, USEPA will
16 decide this and there will be a comment period. I should
17 also note that, on the far right, we have the biomass-based
18 diesel, it goes up to one billion gallons in 2012, and then
19 the same throughout this period. I further anticipate that
20 this number will rise. That is, as you will see when we go
21 through the biodiesel numbers, a very modest goal, as
22 opposed to the other renewable fuels, which is a fairly
23 aggressive goal. So that is likely to change as we move
24 forward, but these are the numbers we use to figure out how
25 much we would need in California. This just takes those

1 numbers on the table and displays them on a chart over
2 time. As you can see, in 2008, there was more Ethanol used
3 in the United States, conventional Ethanol, than the
4 obligation -- about 600 million gallons. And those are
5 probably excess RIN crests that have been banked, and there
6 are likely some RIN crests that were also carried over into
7 2008. We do not know what those numbers are. But the over-
8 compliance is probably much greater than as portrayed there,
9 or at least greater than. But we do not know how much more.
10 So that will help in 2009 for compliance.

11 Now, how much Ethanol were we going to use here?
12 Well, we set some ground rules in our analysis, we assumed a
13 couple things, first of all, that fair share calculation, we
14 are going to blend the Ethanol here, not purchase credits
15 outside of the state borders, so, you know, physical
16 blending and physical requirements for renewable fuels,
17 primarily Ethanol, here. Secondly, we assumed that there
18 was really no credit purchase to help you with regard to
19 compliance. You have to do it by volumetric blending each
20 and every year, and I think a third important point is how
21 much Ethanol can you blend into gasoline. Well, we think
22 California is going to have an upper limit of 10 percent,
23 which we expect to be at next year. There is discussion of
24 E15, 15 percent by volume Ethanol and gasoline, going above
25 the 10 percent Ethanol "blend wall," as people refer to it.

1 EPA is considering comments on that request as a waiver and
2 there should be a decision some time later this year, we
3 hope. But even if EPA does approve E15 for higher Ethanol
4 blend wall, do not believe that will be a viable option in
5 California. California's gasoline regulations are based on
6 data and testing and vehicles and fuels up to 10 percent by
7 volume of Ethanol. There is no data and analysis on the
8 emissions impacts beyond E10. So the Air Resources Board
9 would actually have to go get new data, do new vehicle
10 testing, or obtain vehicle test data that is applicable to
11 California fuels and vehicles, and then rework those
12 equations, re-workshop, develop a whole new regulation, that
13 is a multi-year process, if that was pursued. So at this
14 point, we assume California is going to be E10 max in low
15 level blends, and any Ethanol beyond that in gasoline would
16 have to be in the form of additional gallons of E85. And we
17 will see why that is pretty important.

18 So we look at that as a worst case ethanol demand
19 scenario for both the high and the low demand. And as you
20 will see, I will show you and Malachi showed you the initial
21 -- what I refer to as the initial gasoline demand forecast -
22 - they will change. In the RFS2, the federal mandate drops
23 those numbers further, drives those numbers down,
24 significantly increases the E85, the retail infrastructure
25 that is necessary to accommodate that kind of volume, and

1 especially important, the number of vehicles you will need
2 to actually use that kind of fuel.

3 So here are the numbers. They do rise rather
4 dramatically, quickly, 1.5 billion gallons, 2000 and below,
5 and upwards of almost 3 billion gallons of ethanol. And
6 this will be of all types of Ethanol, of course, by that
7 time. So these are very aggressive growths, but they are
8 driven primarily by, or solely by the RFS2 obligations and
9 how we calculate fair share. Just to point out that we did
10 use two different EIA forecasts, Malachi touched on this.
11 We compared our high price, which is a low demand forecast,
12 with EIA's revised base case, which is a high price. So
13 that is sort of the denominator used to figure out what
14 percent of gasoline do we have each year in a forecast
15 period, relative to the nation. And that is how you figure
16 out what your fair share is. Same thing we do for the high
17 demand case, which is a lower price. We use the low price
18 EIA from their annual energy 2009. So you end up with these
19 two sets of numbers and those are all in the report, all the
20 numbers themselves, I am just showing them graphically here.

21 What I like to point out in this slide is
22 basically that we expect, even though I state that next year
23 we think we are going to beat E10 in just about all the
24 gasoline, not necessarily so, there are some portions of the
25 distribution infrastructure that are proprietary, refineries

1 have their own pipelines, distribution terminals, they do
2 not necessarily have to go to the E10, as Kinder Morgan, the
3 common carrier pipeline is doing January of next year, but
4 if they want their gasoline to remain fungible, or able to
5 be continually traded, if they have an upset problem, or
6 exchange agreements, then they too will have to be at E10.
7 So not necessarily every gallon, but a majority of the
8 gallons in 2010, we are anticipating in the analysis all of
9 the gallons. I just point out that it does not necessarily
10 have to be so. But by 2012-2013, RFS2 will basically
11 require all the gallons of E10 to meet compliance with fair
12 share in California. And beyond that, a whole bunch of E85.

13 So here are the load demand forecast numbers, and
14 the upper dark line is the band or the trend that Malachi
15 showed you earlier, and then overlay the RFS2 obligation,
16 and it pushes that demand for gasoline -- in this case, E10,
17 these are E10 gallons -- down by 9 percent by 2020, 9
18 percent further by 2020, and 12.3 percent by 2030, so that
19 is a significant further dampening than the already low
20 gasoline demand forecast. And, as Malachi stated, well, why
21 is that happening? E85 gallons are going up and they are
22 displacing, in part, on an energy basis, a certain portion
23 of E10 gallons. And the increase is rather dramatic, going
24 up to almost 2 billion gallons. So that is what it looks
25 like. Those are the impacts on the gasoline and the E85

1 and, oh yeah, the bottom line here? The red number? That
2 is the base case. There is a base case forecast for E85 in
3 California, it is based on consumer preference surveys, the
4 number of vehicles currently in existence in California,
5 flex fuel vehicles, and the percent of time a consumer
6 elects to purchase E85 when they go to a location that has
7 both gasoline and E85 available. And that is a very small
8 percent of the time when the price is the same on a gasoline
9 gallon equivalent basis. And I will get into this in just a
10 minute why that is important. So the base case modeling
11 assumed very little E85 even though there are a rather
12 significant number of vehicles in California.

13 High demand, the impact is similar. We see a
14 further dampening of gasoline demand from the initial
15 forecast, 7 percent, by 2020, 8.7. Not as bad. And then
16 the E85 volumes are up a little bit higher, a little bit
17 more than two billion gallons.

18 COMMISSIONER BYRON: Now, before you go on --

19 MR. SCHREMP: Sure.

20 COMMISSIONER BYRON: Mr. Sparano is still here and
21 I am not going to put him on the spot, but I just wanted you
22 to know that we certainly would be interested in hearing
23 from you in written comment as to whether or not staff has
24 this particular issue correct, Mr. Sparano, and if you want
25 to comment now, that would be fine. But I am just

1 interested in hearing these pressures on Ethanol, on E85,
2 and the E10, if indeed these demands look realistic for
3 these commodities. Written comment would be fine.

4 MR. SPARANO: Thank you for the astute
5 observations and I will be really brief, but we will provide
6 something more complete. But one of the big issues here
7 that I think Gordon and the staff know very well is you have
8 an RFS2 requirement that is way way beyond, even if your
9 fair share calculation is a little bit off, way way beyond
10 what we can currently put in gasoline with the 10 percent
11 blend wall, and the requirement to have E85 be not only
12 available in the marketplace, but available in abundance
13 with a full infrastructure in refueling is what makes it a
14 big challenge. And until and how that happens, it is going
15 to be difficult to get beyond the 10 percent, only 10
16 percent, and the falling gasoline demand requirements as
17 depicted here in the staff report will make it even more
18 challenging. So this is one that is going to bear a lot of
19 good policy work and collaboration in order to meet both
20 needs.

21 COMMISSIONER BYRON: Thank you. I look forward to
22 your written comments on that. Mr. Schremp, go ahead.

23 MR. SCHREMP: Thank you. A good segway, there are
24 a few issues you might say, with regard to E85 retail
25 infrastructure. And to be fair, there has not been a strong

1 development of E85 infrastructure in California, there has
2 been in other states that have probably been -- have a
3 stronger support among some consumers in terms of E85
4 purchasing from their FFV vehicles. But in California, a
5 lot of FFV vehicles, but not a lot of opportunity. That is
6 changing. Over the last year, there was at least 26
7 stations available to the public now that have E85
8 dispensers, and that number is growing. Propel is one of
9 the companies that has been very aggressive in this area to
10 try to have more E85 available to tap into that market of
11 FFV vehicles. But as you will see soon, from our outlook,
12 you will need a heck of a lot more than what has been done
13 so far, but to be fair, there has not been this mandate, if
14 you will, that is going to result in what we believe are --
15 you actually have to sell a whole bunch of E85.

16 VICE CHAIR BOYD: Might not the Low Carbon Fuel
17 Standard provide such vehicle, pardon the pun.

18 MR. SCHREMP: The Low Carbon Fuel Standard will
19 actually exacerbate the challenges. I am only speaking
20 specifically of the dramatic E85 increase and the
21 infrastructure needs from RFS2. But, Commissioner Boyd, you
22 are right, the Low Carbon Fuel Standard will possibly be
23 requiring an even higher concentration of E85 than staff has
24 indicated in the report, and that is part of the
25 uncertainties, and I will get into that in just a few

1 minutes.

2 VICE CHAIR BOYD: Okay. And my other thought was,
3 Mr. Sparano pointed out that the industry has not the
4 foggiest idea how to meet the Low Carbon Fuel Standard, but
5 you get credit for alternative fuels, this is an alternative
6 fuel they may choose to put on an island or many islands
7 throughout California -- only a thought.

8 MR. SCHREMP: Okay. Well, just I think stepping
9 back 30,000 foot level, you look at the RFS2 regulations,
10 they are really for the people that are bringing in the fuel
11 and producing the gasoline. Those are sort of the obligated
12 parties, if you will, primarily. Really, the retail station
13 owner and operator, which in the United States, standing
14 California, the majority of the stations are owned by a sole
15 owner, meaning one person only owns one station, and that is
16 it. That is over 52 percent of the stations in the United
17 States. So these are not company owned and operated, big
18 oil company retail outlets, this is really independent --

19 VICE CHAIR BOYD: How many of those are branded
20 though?

21 MR. SCHREMP: Yes, and those are supply
22 agreements, that is correct. But most of the obligations
23 for what you have at your station, and what infrastructure
24 you may elect to alter, those are decisions by individual
25 owners in many cases. So that will be part of the challenge

1 that I will point out. So staff looks at that as an
2 apparent disconnect, if you will. A large obligation by
3 providers of fuel, yet where is the infrastructure
4 requirement? There really is none, and it also extends to
5 where is the vehicle availability requirement. So two areas
6 of concern and certainty at this point that certainly have
7 time to be worked out as we move forward.

8 So speaking of retail infrastructure, staff looked
9 at some different assumptions about the amount of fuel going
10 through a typical dispenser, if you will, and the greater
11 the amount of volume per year, such as 450,000 gallons per
12 year, you end up with a smaller need, this is the two lower
13 numbers down here of additional E85 dispensers, upwards of
14 nearly 5,000. Now, I will also point out that this chart
15 that I am using here this morning is slightly different than
16 the one in the report. The one in the report used an
17 incorrect reference in a dataset, so these are the correct
18 numbers and we will certainly have this revised chart in the
19 corrected staff document once we finalize that. But they
20 are in the same ballpark, just a little bit lower. And
21 then, if you assume that, for example, we are at about
22 150,000 gallons, then it is these two sets of middle
23 numbers, you are well over 10,000 additional E85 dispensers
24 necessary to meet just the RFS2 E85 obligations for E85.
25 And then, if you go up to a level of that of what Minnesota

1 is currently selling per -- these are actual figures,
2 74,000 gallons per year for all their E85 dispensers. They
3 have a good dataset and you will have to obviously have far
4 more dispensers if that is the case, if that is the
5 throughput per E85 dispenser at that future time. Now, a
6 good reference point, if you will, is how many dispensers
7 are there in California at all the stations? Forty-two
8 thousand. That is for all fuels -- premium, mid-grade,
9 regular grade gasoline, diesel fuel -- at retail, and a
10 small amount of alternative fuels. So these are very
11 significant numbers of additional E85 penetration that we
12 believe would be necessary to achieve compliance with just
13 the RFS2, let alone how the Low Carbon Fuel Standard may add
14 to this requirement. That kind of restructure, like
15 anything else, has a cost. We have seen cost estimates
16 ranging in between \$50,000 to \$200,000, that is a very large
17 estimate. I think the National Renewable Energy Lab and
18 some of the papers, White Papers they have done, looked at a
19 number of, I think about \$60,000-\$70,000 as a benchmark.
20 Put that number in context, if you are one of those single
21 sole station, single owners, those kinds of people were
22 averaging less than \$33,000 pre-tax profits, so what kind of
23 money do they have available maybe to get financing or even
24 pay for cash for some of this? That will be a challenge.
25 And we have to look at that all those stations, or most --

1 not all -- most of the stations that have installed E85 in
2 California have done so with some partial financial
3 assistance, or even complete assistance from other funding
4 sources, so it is not basically their money, so that is
5 obviously going to have to change, unless there is a policy
6 in the state that says, okay, well, we are going to spend
7 upwards of -- and I know the figures -- it is a couple of
8 billion dollars to get this done. So that is certainly
9 something to consider, but we are not suggesting -- staff
10 has not suggested that in this document.

11 And another issue that was raised in the April
12 workshop was the fact that Underwriters Laboratory does not
13 have an approved E85 dispenser. This issue is being worked
14 through. It is our understanding that those new E85
15 dispensers have been installed after receiving waivers,
16 essentially, from local agencies. But if one is going to
17 have widespread distribution of E85, we do not know if that
18 current model will suffice, moving forward. We will have to
19 see.

20 Now, does this make good sense from a business
21 perspective to spend that kind of money? As I mentioned
22 before, you are looking at an equipment investment of
23 \$60,000, how much margin do I have to have per gallon of E85
24 to break even? This is just to break even. So this assumes
25 we are making a 10 percent return on investment. You have

1 to be probably in the neighborhood of less than \$.20 per
2 gallon for every gallon of E85. And the most sensitive
3 aspect to this is how much volume per dispenser on an annual
4 basis. So if you increase the volume up to 140,000 gallons
5 a year, you can reduce that margin to about \$.12 a gallon.
6 But if it is less than the assumed \$70,000, then you have to
7 have higher and higher margins just to break even, not make
8 a profit, just to break even with a return investment of 10
9 percent. Now, as another point of reference, all this year
10 in California, so far, I think through the first week of
11 August, we have seen an average margin at retail of \$.12,
12 which his down here. So once again, just on a pure business
13 sense perspective, this appears as though it will be a bit
14 of a challenge, as well, assuming a \$60,000 investment.
15 Make this a \$100,000 investment, then the numbers on these
16 minimum margins go up even greater. So something to keep in
17 mind.

18 Another aspect of widespread E85 sales at retail
19 is that the -- a gallon of E85 will not take you as far in
20 your car if you operate a flex fuel vehicle, as compared to
21 a gallon of E10. And those estimates range between 22 and
22 20 percent less distance, or a reduction in fuel economy.
23 So staff has considered, well, what would be optimal for
24 consumers? Maximize the amount of information to a consumer
25 in California so they can make a more informed decision.

1 Well, gasoline gallon or fuel economy equivalent pricing
2 requirements at California retail would be a good start. So
3 we have concluded that, if the Division of Measurement
4 Standards were to look into this and pursue that kind of
5 requirement, I guess in order of consumer fairness and more
6 informed decision-making, we think that would be beneficial.
7 And the reason is, a national study of E85 retail pricing
8 shows that consumers were actually over-paying by an average
9 of \$.29 a gallon, compared to what the lower green line is
10 on the gas and gallon equivalent pricing. Now, they may be
11 electing to do this of their own volition because they
12 think, "Oh, it is more green, I want to do that," but the
13 fact of the matter is, in almost every other location in the
14 United States, there is not gas and gallon equivalent
15 pricing. It is just, "Here is the price per gallon of E85,
16 here is the price per gallon of gasoline." And so the
17 consumer would have to know how much Ethanol is in the
18 existing gasoline, would have to then do a calculation based
19 on the fuel economy differential with a calculator, and then
20 say, "Ah, yeah, that price is cheaper. I will go ahead and
21 buy it." But they do not see that. They see a price
22 difference of \$.25, \$.40, \$.50, and go, "Oh, great deal,"
23 not necessarily so. It depends on what the base gasoline
24 price is. And to put that in perspective, if gasoline is
25 only \$2.00 a gallon, the E85 would have to be priced \$.44 to

1 \$.56 per gallon less than that number. Now, it has been
2 raised as a potential source of additional funding, or a way
3 of offsetting this discount that a retailer would have to
4 post to attract enough E85 supply -- purchases -- is these
5 renewable identification number of credits, they do have
6 value. And once again, I mentioned the retail station owner
7 and operator has no RFS2 obligation, but who gets the REN
8 credits for the E85? That is a good question. That is a
9 question open to debate. We understand those branded
10 stations with those supply agreements, some of those supply
11 agreements are being re-written to clarify who gets that
12 because this is money, it is over \$.10 a gallon, it is as
13 high as \$.16, and as we move forward these values could
14 rise, or they could drop, there is no certainty there. But
15 this is a tangible value that could be used if the retail
16 station owner is accruing these, it could help offset that
17 lower price that they will have to offer for E85. So we
18 will continue following this and this will start to become
19 more evident as we get closer to 2010-2011.

20 The final component of E85 that is very important
21 is an adequate number of vehicles to actually use the E85,
22 sort of the chicken and the egg extension from retail now to
23 the vehicle side. We have a significant number, 382,000 as
24 of October of 2008, but that number is going to have to grow
25 significantly, 2.4 million by 2020, and over 3 million by

1 2025. Now, the number of vehicles that staff is
2 calculating depends on how frequently you are electing to
3 put in E85. Do it all the time? That minimizes the
4 projection of additional FFV vehicles. Do it half the time,
5 twice as many. So this next slide sort of points that out.
6 This is the track of FFV vehicles in the population in the
7 database. This lower number on this left-hand side scale is
8 the percent of time they elect to put in E85 when there is a
9 filling event. As you can see, it never exceeds 10 percent.
10 So that is a very low rate, and that is based on consumer
11 preference surveys, responses on E85 price at the same price
12 as gasoline, on an energy equivalent basis. So that tells
13 us, at least in this California sampling surveying that
14 consumers will want a further discount in E85 price before
15 they put that in their E85 vehicle. So that is important.
16 So you see this divergence is based on the increase in E85
17 gallons and how many additional FFV vehicles will be
18 required, assuming 100 percent E85 filling, which we believe
19 is unrealistic.

20 These other numbers are 75 percent -- the higher
21 numbers, and so we do not even show 50 percent, which would
22 probably take you above 4 million vehicles, FFV vehicles, by
23 2022. So a significant number of E85 dispensers anticipated
24 would be required to meet RFS2 obligations for E85 and a
25 significant increase in the number of FFV's available. Now,

1 we do mention in the report, but I do not have on a slide
2 here, that there are other policies, if you will, to reduce
3 gasoline demand, and that may include additional hybrids,
4 plug-in, hybrid electric vehicles, full electric vehicles,
5 fuel cell vehicles, these kinds of vehicles are not
6 necessarily FFV's, obviously, and so the automobile
7 manufacturers have an increasing challenge under Pavley to
8 offer more and more fuel efficient vehicles.

9 So here is where we could see another possible
10 sort of fighting out of two policies, one where a whole
11 bunch more E85 requires a whole bunch more FFV's versus,
12 "Well, I do not want to sell my FFV because I want to get
13 Pavley compliance, I want to sell something else." So it is
14 something that bears further investigation to see how this
15 might work out, but once again, another challenge and
16 uncertainty that we discovered in our analysis.

17 Now, after covering the federal standard, we will
18 switch gears to the California standard, we have already
19 mentioned this a couple times, the Low Carbon Fuel Standard
20 is a carbon reduction per gallon standard, so reducing the
21 intensity of that gasoline gallon, and that is done
22 primarily through uses of other blend stocks that are lower
23 in carbon, and the commercially available ones right now are
24 Ethanol and, as Mr. Sparano pointed out, not necessarily all
25 Ethanol is lower in carbon intensity, and that is correct

1 and I will show that next. But this kind of shifting of
2 from the Low Carbon Fuel Standard will likely shift the
3 flavors of Ethanol required to meet compliance, which is
4 different than the volume metric, absolute volume metric
5 fair share just for plain old Ethanol that we have
6 calculated under our RFS2 analysis. So the purpose of this
7 chart is to, "How long can I use a certain type of Ethanol
8 in E10 blend?" Now, we admit that compliance can be
9 accomplished through purchases of credits from mobile source
10 vehicles, so that helps maybe to extend the amount of time
11 you use a certain type of Ethanol in an E10 blend. I could
12 also blend a higher concentration of E85 earlier, and then,
13 in my total mixture, I still come out complying with the Low
14 Carbon Fuel Standard. But at some point you are going to
15 run out of credits and you are going to run out of E85
16 blending to allow you to continue use of E10. So this is
17 certainly an issue because, as I point out in the RFS2
18 compliance, we show continued use of E10 all the way through
19 the forecast period.

20 E85, on the other hand, has a number of different
21 Ethanol types in California, or Brazilian, these are
22 commercially available now, that can be used in E85 blend
23 mode and achieve full compliance with the Low Carbon Fuel
24 Standard. But once again, we do not anticipate the entire
25 state going to E85. That seems unrealistic, extremely

1 costly, and would raise questions about even supply
2 adequacy of Ethanol, beyond the large numbers under the RFS2
3 calculation we have already come up with. So there is an
4 awful lot of uncertainty still in the Low Carbon Fuel
5 Standard, less uncertainty in the gasoline because there are
6 a number of pathways that have been identified, and their
7 carbon intensity is both direct and indirect. Most recently
8 two new pathways, included here, for Brazilian sugarcane,
9 one you are actually producing electricity at your Ethanol
10 plant in Brazil, and excess electricity, and in another you
11 are actually mechanical harvesting of the sugarcane, rather
12 than burning the field ahead of time. So those are
13 important changes and they have improved the carbon
14 intensity, lowered them, if you will, and it has helped on
15 the E10 side, but is not that important on the E85 side,
16 unless you are looking at the mixture of the two.

17 So there is still a lot of uncertainty here. We
18 know that there are other means of compliance. We are
19 looking at it per gallon for the fuel compliance. We know
20 it is not as simplistic as that, it is more involved, more
21 complex, and does have additional flexibility, but that has
22 an awful lot of uncertainty, the amount of credits that may
23 or may not be available from a original engine manufacturer
24 for these other types of vehicles, and, as I will talk about
25 in the biodiesel side, there are still pathways that have

1 not yet been identified, or quantified, into their carbon
2 intensities that will allow us even to calculate how much
3 additional biodiesel could be required, and I will talk
4 about that in just a little bit. Any questions before I
5 switch over to the supply side?

6 As you saw from the production increasing of
7 Ethanol, yes, of course we are using it more in the United
8 States, over 700,000 barrels per day, and, yes, you like the
9 change of the units from gallons to barrels, but be that as
10 it may, and as you can see from this busy chart, the red are
11 imports and you do not really see a lot of imports most of
12 the time, in fact averaging only 1.2 percent in 2009, so a
13 small component of total supply, but at times, back here, in
14 2006, a very important component. Now, where do those
15 imports come from? Primarily Brazil, the second largest
16 Ethanol producer in the world, and an important source, we
17 think, moving forward, and we will talk about that, as we
18 transition to greater Ethanol use in California, and greater
19 E85 use, under the umbrella of the Low Carbon Fuel Standard.

20 No surprise that, when you look at the average
21 concentration in gasoline in the United States, including
22 California, is over 7 percent and that is through May of
23 2009, that average concentration will obviously keep rising
24 as the RFS2 obligations kick in through 2022, and depending
25 on what the gasoline demand does, it may rise at a faster

1 pace if the gasoline demand is either flat, or actually
2 declining, because that is the base of your denominator.

3 Now, more Ethanol production, greater Ethanol use,
4 increased concentration in gasoline, wow, the Ethanol
5 industry must love that. Well, yes and no. A measure of
6 profitability of gross profit per bushel of corn processed,
7 assuming 2.8 gallons of Ethanol per bushel of corn, you see
8 that, by this index, if you will, a rather steep drop in a
9 measure of profitability, and a bit of a rise, a recovery in
10 most recent numbers through the end of July. Good news. So
11 this is primarily due to an over-supply of Ethanol beyond
12 either targeted Ethanol concentrations in non-mandated
13 markets, gasohol blending, E85, such as that. There is
14 plenty of supply right now. And on top of that, there was a
15 large run-up in the feedstock price of corn last year, and
16 still rather pricey now, and that has hurt the profitability
17 of facilities. So we expect this is temporary, as RFS2
18 mandates continue to grow, that this kind of profitability
19 measure will rise over time possibly back to a level,
20 certainly sustained over a dollar, maybe possibly two. But
21 certainly time will tell and it is dependent upon additional
22 capacity that is being constructed, although many of those
23 projects canceled or delayed because of the poor economy and
24 the downward trend in gasoline demand.

25 So no surprise here, with poor economics you have

1 had people shut their plants voluntarily, temporarily,
2 cease operations, and that is what this blue color is in
3 January '09, and in June '09, a large amount of idle
4 capacity. The red bars are the amount of what is under
5 construction at that time, at that snapshot. And obviously,
6 as you see here, a large amount under construction. "Well,
7 gosh, by the time I get here, my production should be up
8 there." Well, how come it is not? Well, some of the
9 construction projects typically are delayed, and in some
10 cases cancelled, never come to be built. But, as you see,
11 the capacity continues to climb and we suspect this will go
12 upwards of 15 billion gallons before all is said and done,
13 and it is getting close, right now, a little over 13 billion
14 gallons of actual in-place capacity with some more under
15 construction. And what is the magic 15 billion gallons?
16 Well, that is the RFS2 conventional Methanol from corn
17 limit, 15 billion gallons in the standard. So you can blend
18 more, but you are not helping achieve compliance with
19 anything by doing that.

20 Now, that is conventional Ethanol. Cellulosic, I
21 think this was touched on by Mr. Sparano. Cellulosic
22 Ethanol currently 4 million gallons per year of capacity,
23 operational. Another 5 million could be by the end of this
24 year. So that is almost 10 million gallons. The obligation
25 starting January is 100 million gallons for 2010. It is

1 unlikely there will be that much of cellulosic Ethanol
2 available to meet the obligation. We have concluded --
3 staff has concluded that, instead of setting this standard,
4 and clearly there are some challenges of meeting that goal
5 by the producers, that you may want to consider something
6 that Oregon has elected to utilize and that is build it
7 first and then the regulation kicks in, and that is what
8 they have done with their biodiesel standard that has just
9 kicked in. Once the biodiesel facilities are at a certain
10 level, for three consecutive months, then the regulation for
11 blending downstream kicks in on the obligation. So it is
12 something the EPA may want to consider, but we probably
13 suspect they are getting an ample amount of comments on
14 cellulosic Ethanol portion of the regulation in the comment
15 period. And so we will find out what EPA does do, and also
16 acknowledge that EPA does have the ability to alter,
17 suspend, delay a component of RFS2, but think of yourself as
18 an obligated party trying to comply ahead of time, setting
19 up your contracts, your supply agreements, you need a little
20 bit more certainty than, at the last minute, somebody comes
21 in and says, "Ah, there is not enough, I'll just cancel
22 that." So that is certainly an issue and will become more
23 of an issue if there continues to be a problem making
24 cellulosic Ethanol viable on commercial basis, and cost
25 competitive, because the obligation is to ramp up rather

1 quickly over the next five years.

2 So I guess on the U.S. side, we have to say, for
3 the next couple years, should be ample supply to meet the
4 RFS2 obligations. So now we will take a look at Brazil and
5 Brazil's importance, especially for the Low Carbon Fuel
6 Standard in California. Just to compare and contrast real
7 quickly, the average output from a plant in the United
8 States is about 50 million gallons a year, and a little less
9 than 20 in Brazil -- smaller plants in Brazil, more of them.
10 And another important thing is, the Brazilian facilities
11 will actually -- they are looking at another market. This
12 is not just, "Where can I sell my Ethanol, my primary
13 output, and I have some co-products like in the United
14 States?" If they have distiller dried grains, for example,
15 it is a co-product they also sell and has value. Well, in
16 Brazil, every year there is this, well, how much -- what is
17 the price of sugar? How much can I sell my sugar from?
18 Don't convert the molasses to alcohol, just make it into
19 sugar and sell it to the world sugar market. And Brazil is
20 a huge provider of sugar on the world market. So, as those
21 sugar prices go up and down, or supply and demand
22 fluctuates, some of that Ethanol or that sugar cane more
23 wants to go into the world market, so there is that
24 interactive dynamic, if you will, that constantly goes on
25 the Brazilian market. In addition to that, the amount of

1 Ethanol in gasoline, at about 24 percent, I think, by
2 volume, at low level blends, is -- that can fluctuate and it
3 can be set at different levels. So there is -- and the
4 demand in gasoline in Brazil can change, and the demand for
5 E85 or almost E100 for their FFV's can fluctuate. So there
6 is this dynamic that goes back and forth that, having said
7 that, it does not guarantee that build an Ethanol plant in
8 Brazil and it is going to produce Ethanol. Now, their
9 production has been going up and you will see here, there
10 are two different types we refer to as hydrous and anhydrous
11 ethanol, in two different growing regions in Brazil, and
12 hydrous basically contains a certain amount of water and
13 anhydrous has nearly the absence of water. The hydrous goes
14 into the FFV markets that is gas containing ethanol anywhere
15 from 24 to 100 percent by concentration, anhydrous goes into
16 the low level gassing blends. Some hydrous ethanol is also
17 exported to some Caribbean basin countries and those
18 facilities will take that Ethanol containing some water,
19 they will dehydrate that, get that water out of there, make
20 it anhydrous Ethanol, and then export that to the United
21 States, so that is another means of hydrous Ethanol getting
22 to the marketplace on a global scale. Speaking of global
23 scale, you see the exports of Brazilian Ethanol have been
24 growing over time, reaching a record level in 2008, almost
25 1.4 billion gallons. We expect that to go up in the future

1 because we think there will be a strong demand certainly in
2 California, and also in the United States for advanced RFS2
3 compliance. And just to point out that there is an import
4 duty and to add more on tariff on Brazilian ethanol, and
5 other foreign countries outside the Caribbean basin
6 initiative, and that does, I guess, make it costlier in some
7 analysis that we have looked at, some economic modeling
8 analysis that we have looked at, suggests that the price of
9 Ethanol in the United States could be lowered by anywhere
10 from 2.5 to 14 percent, a modest amount, if you will, yes,
11 but still a reduction that could then be passed along to the
12 consumers, at least a portion of that. So this does, in
13 effect, increase the price of providing Ethanol to the
14 marketplace in the United States, but we also understand, on
15 the other side of that coin is this is a bit of
16 protectionism that is probably designed to help the domestic
17 ethanol industry, and so there would be some pain and
18 suffering on the Ethanol industry side, and domestically
19 speaking if this is removed, as well, most likely.

20 So some Brazilian estimates. UNICA, the sugarcane
21 trade group, and ETBE, which is basically their energy and
22 mines association, they have forecasts of growing exports,
23 these are billions of gallons, and California use would want
24 most of this over -- or a large part in here -- over the
25 next five to 10 years, so we do hope that this does come to

1 pass, but there are competing forces for Brazilian exports,
2 it does not necessarily go here, and it is not necessarily
3 the highest price. For example, Memorandums of
4 Understanding with Japan, as Japan tries to achieve carbon
5 reductions, they have elected to increase the amount of
6 Ethanol being used in their gasoline, albeit in the form of
7 an ether, ETBE, rather than just pure Ethanol blending at
8 this point, but their demand is going to go up and they are
9 looking, and they have some supply agreements in place in
10 Brazil to obtain the necessary Ethanol for use in their
11 country. So more Ethanol exports from Brazil, yes, but not
12 guaranteed they will come to California, not even to the
13 United States, let alone California, so this is another
14 competing force for a type of low carbon intensity Ethanol
15 we think is going to be necessary to meet Low Carbon Fuel
16 Standards in California.

17 Now, there has been a mention of logistics and
18 certainly the complicating factor, one aspect of the Low
19 Carbon Fuel Standard, is the flavor of Ethanol, that has a
20 lot of uncertainty associated with it, but the issue is it
21 does not come by the same logistical chain of events to get
22 to the retail station. Where that comes from, how it gets
23 into the state initially, are different means of conveyance.
24 And so this is important in terms of compliance with the Low
25 Carbon Fuel Standard in how companies are actually going to

1 do this, is what kind of instruction will then be necessary
2 because, as you can see here, the dominant amount of Ethanol
3 is coming in via rail cars. Now, there is an infrastructure
4 in place, especially in Southern California with the unit
5 train unloading facility, it is very efficient, the systems
6 worked very well, the industry has responded remarkably well
7 to ensure an adequate supply without interruption. So this
8 system is working very well. We do have a growing in-state
9 production up through 2008, and then that economic
10 profitability news for Ethanol producers, I showed you
11 earlier, well, that translates through to California
12 facilities, and basically all but one facility in California
13 is shut down, I believe, at least at the time we were doing
14 the report, and is idle. So we expect those facilities to
15 come back as economics improve, and so we will see more in-
16 state production, but mostly we are an importer of Ethanol,
17 and rail Ethanol for the Midwest. We do get a little bit of
18 water-borne Ethanol foreign imports, Caribbean Basin
19 Initiative Ethanol, and Brazilian Ethanol, but a small
20 amount because it has not been necessary, there is plenty of
21 domestic Ethanol available. So our rail infrastructure in
22 place, distribution terminals set up to do this, but that
23 has been at a level of about 6-7 percent. Kinder Morgan is
24 going to go to E10 and they handle the majority of the
25 gasoline in California, and they will be accepting base

1 gasoline that only gets blended with 10 percent Ethanol.
2 So we expect most of the system, the rest of the state, will
3 follow suit. We think it is likely there is inadequate
4 infrastructure in place, there is some question about how
5 quickly the rail facility in Southern California can ramp
6 up, this has to do with some uncertainty of some of the
7 participants in the marketplace willing to sign-up to do
8 that, because of when they think E10 is necessary versus
9 when the market is going to transition. So that is still
10 being worked through, so we are following that closely. And
11 there are also modifications that have already been
12 accomplished through the distribution terminals, more
13 storage tanks for Ethanol and a greater ability to receive
14 more trucks, because that is how the Ethanol gets in the
15 distribution terminal is via truck, almost solely in
16 California, but that is not how it initially gets to the
17 state, that is by rail. So as I mentioned, 86 percent by
18 rail. Kinder Morgan is working on a project in Northern
19 California, in the Richmond area, to be able to bring in
20 unit trains in Northern California, that would be a first,
21 and it is a different process in that the tanker trucks are
22 loading directly from the rail cars, it is called a trans-
23 loading process, and I believe Kinder Morgan is going to
24 talk about that today. So if that project is completed, we
25 think there will be sufficient rail import capability in

1 Northern California to handle this increase to 10 percent
2 Ethanol and we do not anticipate any problems there. Marine
3 facilities, on the other hand, we are not quite sure if
4 there is adequate capacity to bring in water-borne Ethanol,
5 a significant amount. We understand that various marine
6 terminals can use tanks that are in another service, like
7 gasoline, or gassing blend stock components right now, but
8 when you use an existing tank that is already in service for
9 another service, then you are decreasing the import
10 capability for that other type of commodity. But in time,
11 this can be worked out. There are two ways to bring
12 Brazilian Ethanol into California. One way is directly to
13 an existing marine terminal that is adequately set up, there
14 are a couple that can already do this. And then another is
15 to bring into a marine terminal in another part outside of
16 California, load into rail cars, and bring those rail cars
17 into California and use the existing rail receipt and
18 offloading facilities. So those are two means we see viable
19 for increased amounts of Brazilian Ethanol. Primatefuel, who
20 is here today and going to be speaking about their project
21 in Sacramento, does have something like this to accommodate
22 up to 400 million gallons a year of Ethanol receipts, and
23 this can be over the water, and they can -- please correct
24 me if those figures are wrong. But construction has not
25 started. They do have permits in hand, but they have not

1 started construction. They need enough people to basically
2 sign up and to make that the going concern, and we will get
3 an update on that. Brazilian Ethanol going through the
4 Houston Ship Channel, rail cars in California, well, Kinder
5 Morgan will also talk about that. They have a project that
6 they are looking at developing to be able to handle that
7 kind of Ethanol receipt and transfer.

8 If there are not any questions on the logistics, I
9 will keep moving forward and now give you the whole food for
10 fuel that seems to be in the popular press. "More Ethanol?
11 Well, you are going to make my cornflakes go up in price."
12 All right, well, let's take a look at some of the historical
13 information in agricultural statistics and then, more
14 importantly, some of the projections. No doubt, the amount
15 of corn being used for its Ethanol has risen dramatically,
16 almost 3.3 billion bushels in 2008 and, as you can see, in
17 2003, we are a little over 1, so that is more than tripling
18 in a period of six years. And as a percent of total corn
19 use, it is now upwards of 33 percent and, then, once again,
20 you go back to 2002 and it was a little bit less than 10
21 percent, so that is a rather dramatic increase in the
22 percent of corn that is now actually being converted into
23 fuel Ethanol, but no surprise in the strong increase in
24 production. Corn has other uses. The dominant one is feed
25 and residual uses, these purple bars, but as you can see

1 over time, the red bars have been growing in size and, in
2 2009, are projected now at 4.1 billion bushels versus the
3 3.3 in 2008. So are they going to have to plant a whole
4 bunch more corn, acres of corn? Not necessarily. Why? The
5 yield of corn has continued to increase at a remarkable
6 pace, and primarily in the 1980s you saw -- or up through
7 the '80s -- you saw post World War II significant
8 application of fertilizer that increased yields, and then
9 you have seen introduction of better and better strains,
10 more resistant to disease, pests, as well as higher yields
11 per bushel, and then using geo-space information systems
12 where you can actually apply fertilizer, for example, in a
13 un-uniform manner, you apply it where it is needed based on
14 satellite imagery in your field, and not the same
15 concentration over all of your acres. Same with watering,
16 tilling, everything. So these advances have allowed for a
17 remarkable continued increase in yield that is forecast to
18 go even higher. So what does that mean? Well, the amount
19 of acres harvested and the amount of corn certainly can get
20 a little bit higher. Case in point, I am assuming a million
21 acres of corn harvested in 2008, 32 million less acres than
22 the record in 1917, but four times the yield. So about a
23 third less acres and four times the amount of corn, that is
24 because of yield improvements, and those yield improvements
25 are expected to continue. Looking at the forecasts from

1 USDA for plantings, and I have elected to use three types
2 of crops that people consider as trading off one another
3 when I talk about the Food for Fuel, corn, soybeans, and
4 wheat, and we see total plantings are forecasted to go down,
5 actually, not even increased, go down 1.7 percent compared
6 to 2008. Well, their yields are going up which is why their
7 production, in total, actually increased with plantings
8 down. So it looks like there will be higher yields of corn,
9 higher yields of wheat and soybeans, so that is how
10 additional production will be obtained without as much
11 effort as one might think. And this is a look at the
12 forecast for the amount of bushels required to produce
13 Ethanol and it is over 5 billion gallons by 2018 -- 5
14 billion bushels by 2018 to produce the Ethanol. And on a
15 percent basis, we are seeing a leveling out of about 41
16 percent from the 33 percent in 2008. So a little bit higher
17 concentration of corn being used for this purpose, but other
18 corn uses are going up -- feed and residual use, primarily.

19 So it looks like, I guess summarizing, that the
20 agricultural marketplace appears to be able to handle this
21 increase in conventional corn-based Ethanol that is required
22 in the RFS2, so we do not see a lot of issues there. Now,
23 we also want to point out that this is not as controllable a
24 process as, say, a refinery operation is. A lot of the corn
25 grown in the Midwest is dry cropping, it is dependent on

1 rainfall that is occurring in the summertime. Change the
2 rainfall patterns, change the amounts you get, lower yields.
3 Have some flooding, have some freeze events, and you alter
4 the yields. So those projections are certainly not a
5 guarantee, but with fairly high corn prices, the farmers
6 certainly endeavor to try to produce as much as possible to
7 meet these growing anticipated demands, but some of the
8 necessary ingredients to have a successful harvest are
9 literally beyond their control.

10 Now, biodiesel, the production has been growing
11 rather dramatically, not quite 700 million gallons in 2008,
12 this is actual production, not production capacity, which is
13 much higher. So, you say, "Well, we're going to use a whole
14 bunch of that," well, not so fast. A lot of that left the
15 market. Where did it go? It went to Europe, primarily.
16 Well, Europe has a higher marketing price for the diesel
17 fuel and so that is where it found a home. And the European
18 community, the EEU Council said, "Well, let me get this
19 right. You're getting a dollar a gallon to blend in the
20 United States, and then you come over here and compete
21 against our farmers. We don't think that's fair." And so
22 there are basically sort of two sets of tariffs that were
23 put in place for the next five years that are essentially
24 designed to offset that benefit that some of the blenders in
25 the United States were getting from the dollar a gallon

1 credit. So we anticipate that the export quantities will
2 drop dramatically in 2009, and that biodiesel will find a
3 home in the United States, and then rise above these
4 numbers, which never even get above 1 percent in average
5 biodiesel use in diesel fuel in the United States. So we
6 think this will go up. So, a policy to give a dollar a
7 gallon blending credit, and yet really no change in the
8 average concentration used in diesel fuel.

9 The RFS2 does have a biomass-based diesel
10 component and, once again, fair share calculations, our
11 diesel forecast in California versus a comparable EIA
12 forecast for diesel fuel, came up with these numbers. And
13 it never gets to 65 million gallons, so these are rather
14 modest goals, staff believes, for biodiesel use, especially
15 when you consider in 2008 we estimate there was already 50
16 million gallons of biodiesel already being used. So meeting
17 RFS2 fair share in California does not appear to be any
18 problem whatsoever in terms of supply. And that is because
19 there is a tremendous amount of excess capacity in the
20 United States. There is 2.3 billion gallons of production
21 capacity and another 600 million on its way if all of that
22 gets built. So, plenty. Since you may recall, the RFS2
23 requires 1 billion. So there is already plenty of capacity
24 to meet the RFS2 all the way through 2022, but as we
25 mentioned earlier, we think EPA will raise that 1 billion

1 gallon target to higher and higher levels, we just do not
2 know how much, but certainly you could do that, and there is
3 adequate supply to do that.

4 Well, looking at Europe, Europe is the largest
5 producer of biodiesel. They have 2.5 billion gallons of
6 idle capacity due to poor economics of biodiesel producers
7 at this time, like that in the United States. So plenty of
8 spare capacity, if you will, in Europe to tap into it, if
9 necessary, but not even necessary under these modest RFS2
10 goals. This is just graphically displaying that information
11 on a spare capacity, idle capacity, the dark red versus the
12 yellow. And I believe that the actual production capacity
13 in 2009 will approach 9 billion gallons, so much higher than
14 even this chart indicates. So lots of biodiesel capacity
15 coming online in the United States and in Europe.

16 As is the case with gasoline, there are even a
17 greater number of uncertainties for biodiesel under the Low
18 Carbon Fuel Standard, and that is because we do not have
19 enough pathways for where is the carbon intensity for both
20 direct and indirect for different types of biodiesel. What
21 we have now is basically yellow grease, animal fat pathways,
22 but one cannot make a viable argument that that is going to
23 be an adequate supply in the United States. There is a
24 finite limit to that material to convert into a biodiesel.
25 Certainly, crop sources are going to be more of what is

1 going to be used. So, not having the pathway, staff has
2 been unable to analyze what kind of impact biodiesel demand
3 may occur because of Low Carbon Fuel Standard in California.
4 Once those new pathways do come out, we would be doing some
5 follow-up analysis; if it is does rather soon, we will have
6 some of that in the finalized report, but it is likely
7 something that will continue following next year in the off-
8 year IEPR cycle. But just looking at B10 or B20 levels, 10
9 percent level and 20 percent level, we are looking at 400 to
10 800 million gallons, significantly more than the 50 million
11 gallons in 2008. But certainly, adequate supply in the
12 United States to handle that increase, if the Low Carbon
13 Fuel Standard drives you to that level. It could even drive
14 you beyond that, but like I said, we do not know at this
15 point in time. There are some infrastructure issues, but
16 there are some differences compared to E85. Basically, the
17 difference on the retail side is you really do not have to
18 do much of anything. Well, if I am getting diesel into my
19 diesel underground storage tank, well, go ahead and put that
20 B5 blend in there. No harm, no foul, I use my existing
21 retail pumps, pipe, tank, no change. Go to B20, well, okay,
22 maybe I have to change some seals and maybe change my hose,
23 but pretty much very minimal investment. Now, there is an
24 issue on the wholesale side. Why? Where are you making
25 your B5? Well, where do they blend the gasoline with

1 Ethanol? At the distribution terminals. Same thing is
2 going to have to happen with biodiesel. So if you have
3 widespread use of B5, for example, you need basically all
4 the distribution terminals have to have a biodiesel, a B100
5 tank you would tap into to make your B5 blend. So the
6 wholesale infrastructure is going to need some
7 modifications, but this can be done in a relatively short
8 period of time -- 12 to 24 months, not a problem, not a
9 concern, depending on the pace, and depending on whether or
10 not you have a mandate that every single gallon must be B5
11 versus a average statewide goal. Far different impacts on
12 the infrastructure requirements because, then, you could let
13 people who already have the capability to dispense out
14 biodiesel more efficiently up to the point you need the
15 whole market to do that. So there are ways around that.
16 There is an underground storage tank, or UST, issue. The
17 tanks currently in use that have diesel fuel, conventional
18 diesel fuel, are allowed to have B5, but tanks of a
19 concentration higher than 5 percent, up to 20 percent, they
20 have to have sort of independent testing verification that,
21 yeah, that is okay materials-wise to put in B20. That has
22 not been done. The California State Water Resources Control
23 Board has recognized that they do not want to essentially
24 stand in the way of increased use of biodiesel, so there is
25 essentially a three-year variance so you can go ahead and

1 put that B20 in that existing diesel tank underground, and
2 that three years should allow sufficient time to those
3 approvals, if you will, to be worked out, worked in the
4 system, and I think they are taking comments on their
5 proposal through September, and they are welcomed to
6 comment, and we have been working with them before in the
7 past on this issue. So assuming no increase beyond B20,
8 modifications at the retail, again, should be negligible.
9 That does conclude my remarks. Oh, look, exactly noon.

10 COMMISSIONER BYRON: You did very well. And a lot
11 of information, a lot of very good information. A couple
12 quick questions. I am going back to page -- your slide 56
13 where it shows a lot of fluctuation on yields, primarily for
14 corn, so I would expect that that is that seasonal issue you
15 were talking about -- not seasonal -- that is that annual
16 variance that we might see. What might that do with prices?
17 Have we modeled that? Have we looked at that? If we exceed
18 or drop well below demand, what would that do to prices for
19 Ethanol -- food-based Ethanol?

20 MR. SCHREMP: Not being an economist, but --

21 COMMISSIONER BYRON: I am going to ask you other
22 economic questions, too, and you are right, it really does
23 stretch what we ask you to do, I agree.

24 MR. SCHREMP: But economists, even economists on
25 our staff will tell us, that there is a relationship between

1 a decrease in supply availability when demand remains the
2 same, that the prices should go up. And so, yes, we have
3 seen that in the past in these agricultural markets. But I
4 have to say, what happened in 2008 was not supply-demand
5 based as many claimed, with the run-up in the commodity
6 markets. I am talking about corn, soybeans, wheat, and I am
7 talking about oil, and I am talking about copper, all those
8 commodity markets zoomed to the moon. Supply-demand? I do
9 not think so. Then, because they dropped off the map after
10 reaching record high levels, demand did not change. So what
11 was going on there? Well, an awful lot of money was flowing
12 to those markets -- increasing demand for those futures
13 shares. And so that caused sort of an aberration, if you
14 will, both on the crude oil side, as well as in the
15 agricultural markets, and some of that translated through to
16 increased costs for those companies. But that was not a
17 supply-demand reaction in those commodity markets. But we
18 have seen, absent last year what went on, we have seen that
19 corn values can drop, that the farmers are going to receive
20 when it starts to become more known, like, "Oh, we're going
21 to have a bumper year," over-supply, price drops. "Oh, no,
22 didn't get the rains," yield very small, the plants that are
23 behind schedule in their development, okay, prices go up.
24 Yes, that does happen. So, primarily what is going to
25 happen is that those will directly affect the economics of

1 the Ethanol facilities. Now, if the effects are great
2 enough, there will be some more idled facilities on a
3 temporary basis, moving forward. So that is one potential
4 impact of a price increase because of an unforeseen,
5 underdevelopment of a crop in a particular year, for other
6 factors -- lack of rain, bad winter, etc. So, yeah, we
7 expect that those fluctuations were primarily some weather-
8 based and also some -- what you do not see on here since
9 this is the actual bushels harvested, you do not see the
10 amount of acres planted because what happens in these crops
11 is another behavior, if you will, that the farmers will
12 collectively say, "Okay, what were the prices this year?
13 Wow, the prices tanked. I am out of corn and I am into
14 soybeans." And so you see people do actually move -- shift
15 their fields to make an annual crop, they are going to
16 change it every year if they want. So you will see people
17 chase a price -- prices were good? More plantings the next
18 year is usually what you will see. Prices were down? Less
19 plantings, absent anything else. So there is a reaction by
20 the acres planted and there is a reaction in the market and
21 the amount of bushels actually harvested compared to the
22 demand that is anticipated.

23 COMMISSIONER BYRON: Good. You are becoming an
24 agricultural specialist, as well, I can see.

25 MR. SCHREMP: Necessary in this increased

1 renewable world we are in, yes.

2 COMMISSIONER BYRON: I think we will stop here.

3 It is noon. Thank you very much, excellent presentation.

4 We will reconvene at 1:15. Thank you all very much.

5 MR. SCHREMP: Thank you, Commissioner.

6 [Off the record at 12:03 p.m.]

7 [Back on the record at 1:00 p.m.]

8 COMMISSIONER BYRON: Welcome back, everyone. This
9 is Jeff Byron, Chair of the Integrated Energy Policy Report
10 Committee, and with me is Commissioner Boyd, and we are
11 reconvening our Transportation Fuel Forecast and Analysis
12 IEPR and Transportation and Fuels Joint Committee Workshop.
13 It looks like we have got some stakeholder presentations
14 this afternoon. Are you our lead, Mr. Schremp?

15 MR. SCHREMP: Yes, I am.

16 COMMISSIONER BYRON: Good. Go ahead.

17 MR. SCHREMP: Thank you, Commissioner. Welcome
18 back. We are going to start with Joel Velasco. He is from
19 UNICA. And, Joel, in a second I will let you sort of
20 describe what you do for your organization and what UNICA
21 does. I know that is in your presentation. But Joel is
22 going to speak to us remotely and I will go ahead and
23 control the slides. So I will pass the mic to you, Joel.
24 Go ahead.

25 MR. VELASCO: Thank you very much. Everybody can

1 hear me, I presume?

2 MR. SCHREMP: Yes, we can.

3 MR. VELASCO: Great. So my name is Joel Velasco,
4 the Chief Representative for North America, of the Brazilian
5 Sugarcane Industry Association. I apologize for not being
6 there present today. I was in Brazil until Saturday and my
7 family had not seen me in about two or three weeks. I
8 thought I could use the videoconferencing to do this
9 instead.

10 COMMISSIONER BYRON: That is perfectly okay, Mr.
11 Velasco. This is Jeff Byron. We are glad to have you and
12 we are seeing a lot more folks doing presentations by WebEx.
13 That is a good thing.

14 MR. VELASCO: Okay. Well, maybe I will ask CARB
15 to give me some carbon credits. I think I have been in
16 California almost every month this year.

17 VICE CHAIR BOYD: I could buy some from you. This
18 is Commissioner Boyd. I have got a little notoriety lately
19 about not buying carbon credits for travel.

20 MR. VELASCO: Okay, well, again, let's go to the
21 next slide which I believe has -- okay, I just want to make
22 kind of two broad points, one is just to briefly describe
23 the industry and what we are doing in Brazil, what we are
24 producing, because I think it is a critical element of your
25 analysis. I have read through the report, I think you guys

1 have done an admirable job of doing this. I do not know
2 how many times you have been to Brazil to do that report,
3 but if you have not, it is pretty impressive. And then, the
4 second part of this, I really want to talk about kind of
5 meeting the RFS and the Low Carbon Fuel Standard impacts,
6 both from a supply and demand perspective. And then I will
7 be glad to take some questions. Next slide, please.

8 So first, let's talk a little bit about the
9 Brazilian sugarcane industry. I think it has been pointed
10 out before, we produce food, fuel, and now electricity, and
11 I think we will be doing some other products going forward,
12 in fact, some of them with California-based companies. Next
13 slide, please.

14 UNICA is the leading sugarcane industry
15 association in Brazil, representing a little bit over 100
16 producers, both cane growers and mills that are usually
17 vertically integrated in Brazil. Our member companies are
18 responsible for roughly about 60 percent of all the Ethanol
19 and all the sugar that is produced in Brazil. A third
20 product for our company is electricity, we call it bio-
21 electricity for some differentiation, but it is basically
22 co-generation of electricity from the bagasse, which is the
23 dried stock and other materials from the cane process, and
24 it is a byproduct. Today that bio-electricity meets about 3
25 percent of Brazil's electricity needs. We believe, easily

1 within the next decade, we will be meeting about 10
2 percent of Brazil's electricity needs. This is a critical
3 element, I think, of the balance sheet of any sugarcane
4 milled in Brazil today. A lot of focus abroad is on
5 Ethanol, but we like to point out that, when you grow cane
6 and you process it, you get at least three products today.
7 And my presence, whether virtually in this meeting, but
8 around the United States often is part of an effort by UTICA
9 both to educate various groups, but also to try to engage in
10 a dialogue about dealing with some of the challenges and
11 opportunities that we see ahead for our industry. Next
12 slide, please.

13 So I think the report does a pretty good job of
14 describing how Ethanol is produced in Brazil. But let me
15 just try to graphically show you a way to think about our
16 industry. On the left side of your slide there, you see a
17 little bit of sugarcane. We grow about half a billion tons
18 of cane, or at least we will grow more than that this year,
19 and that will be processed into mills. At the mill, the
20 cane is squeezed, and the juice is made into either Ethanol
21 or sugar. I remember earlier in the presentation somebody
22 mentioned Molasses. Unlike other mills in other places of
23 the world, our Molasses is actually -- whatever is left is
24 actually converted back into Ethanol. And then we are left
25 with a dry biomass, a pretty abundant biomass, which is

1 often referred to as bagasse, and that is burned at the
2 mill, at every mill, to produce steam and electricity to
3 power both the mill and it usually leaves quite a bit of
4 surplus electricity to be sold into the grid. So this year,
5 we are estimating for all of Brazil about 7 billion gallons
6 of Ethanol will be produced, about 31 million metric tons of
7 sugar will be produced, and about 15,000 Gigawatt hours will
8 be produced of electricity to the grid. Again, all of these
9 numbers have been increased over time. Just while I am
10 here, let me just try to mention a few things, some that
11 have already been said, but any mill in Brazil, in general,
12 has the ability to adjust how much Ethanol and how much
13 sugar, how much fuel or food, however you want to look at
14 it, it can produce. Due to, in large part, due to the fact
15 that India, which used to be the world's second largest
16 exporter of sugar, I believe, until last year, became a net
17 importer of sugar for reasons unrelated to fuel, the world
18 price of sugar has been increasing quite rapidly, in fact, I
19 think it is one of the best performing commodities today in
20 the world since the beginning of the year. That has led all
21 the mills in Brazil to produce as much sugar this harvest as
22 they can, and so what you are seeing is a return to a lot
23 more sugar production because the price of Ethanol is low.
24 This year, we are estimating that about 55 percent of an
25 average mill's production will be for Ethanol, and 45

1 percent sugar. It is usually within that 60-40 split, but
2 that is important to understand the dynamics in Brazil.

3 What is really driving demand for Ethanol, I spoke
4 a little bit about sugar, is really the Brazilian domestic
5 market for Ethanol. We have two types of Ethanol in Brazil,
6 the hydrous and the anhydrous. The hydrous is what is used
7 in our flex fuel carbs in Brazil, it has about 5 percent
8 water, but because it is a tropical country, we have no
9 problems with E100 blends in our flex fuel carbs, and then
10 anhydrous, which is blended with gasoline. Hydrous Ethanol
11 demand has grown quite rapidly, in fact, total Ethanol
12 demand just this year alone has increased nearly 18 percent.
13 Now, this is at the same time we are suffering from fiscal
14 economic challenges, not just in the U.S., but around the
15 world, we are seeing stronger and stronger demand for
16 hydrous Ethanol. Why? Because Ethanol remains very
17 competitive with gasoline in Brazil. The second reason for
18 a strong demand for Ethanol in Brazil is flex fuel vehicles.
19 For the first half of the year, 92 percent of all the light
20 vehicles sold in Brazil were flex fuel, capable of taking
21 Ethanol in gasoline. In fact, comparing the first half of
22 2009 data with the first half of 2008 data, we see an
23 increase of 5 percent already. Today, we have about a third
24 of the auto fleet of Brazil already flex fuel, and we
25 believe that we will reach 50 percent in the not too distant

1 future. All that does is it provides more flexibility to
2 the consumer because he can opt at the pump to make the
3 choice of fuel based on price. We have in every fueling
4 station in Brazil either gasoline, which is really E25, or
5 E100, hydrous Ethanol, available. I will also note just in
6 passing that we -- historically, Brazil is a little bit like
7 Europe, has a lot of small vehicles. We have now seen in
8 Brazil that Honda launched the first flex fuel motorcycle.
9 For a developing country, motorcycles are a major means of
10 transportation. I think we have as many motorcycles as we
11 have cars, and while we have historically focused only on
12 small vehicles for Ethanol in Brazil, we are now seeing a
13 lot of success with SUVs, or at least larger vehicles, pick-
14 up trucks running on E100 or flex fuel. It is very
15 different than the U.S., where the SUVs were the first ones
16 to go to the E85 in large part, I think, because of the CAFÉ
17 credit. So we have been very successful in Brazil, I think,
18 with Ethanol today and the fact that we use electricity, we
19 now are able to say that 16 percent of Brazil's total energy
20 demand comes from sugarcane, about 45 percent of Brazil's
21 total energy demand is from renewable sources. So we feel
22 we are quite well positioned. In fact, if you go around
23 Brazil today, you discover that gasoline is actually the
24 alternative fuel. Ethanol is the largest fuel used in
25 Brazil, liquid fuel for light vehicle engines. Next slide,

1 please.

2 Then, I think though gasoline is the alternative
3 fuel in Brazil, we have been able to achieve -- to basically
4 replace 50 percent of our gasoline consumption with about
5 one percent of Brazil's arable land. In red there, you see
6 the areas or the regions where sugarcane is grown in Brazil.
7 I was just in South Central Brazil, outside of the state of
8 San Paulo there, which is really the hardest sugarcane
9 country, last week. And we expect that most of the
10 expansion is going to occur in and around those areas. The
11 next slide, please. Next slide. Thanks.

12 The final thing is, just before I will move on to
13 some of the specific issues in the U.S., this is UNICA's
14 estimates, and I think there was a reference to it in an
15 earlier slide, these are the actual numbers that we have
16 projected, both out to 2015 and 2020. These are not based
17 on an incredible amount of scientific work from the
18 standpoint of kind of, you know, hard to plot out what
19 policy changes are going to occur in every country in the
20 world, much less in any states in the world, and also these
21 projections were made before the economic crisis, and we
22 have not yet been able to revise them. But what you
23 generally see there is that we see growth in all areas, both
24 in sugar production, as well as in Ethanol production, and
25 we see very strong growth in Ethanol for domestic

1 consumption in Brazil. Why? Because we are not expecting
2 -- we are not building into these projections the
3 possibility that, on a price basis, even if policies when
4 sent by the use of sugarcane Ethanol broad, then on a price
5 basis will be necessarily advantageous to ship Ethanol to
6 the U.S. I think what is critical for you guys to
7 understand in this context is that, all this really shows is
8 that it is eminently -- Brazil is eminently able to increase
9 supply of Ethanol over the coming years, but a lot of this
10 will depend on the prices and the trade policy associated
11 with it. Just a caveat for those who are really looking
12 closely at numbers; sugarcane harvest in Brazil is really an
13 activity all year long, depending what region you are in,
14 but in South Central Brazil, which is the main area of
15 Brazil for sugarcane production, that production occurs
16 usually starting in April and goes all the way to October
17 and November. And so that is why, when you look at data,
18 you will see two years up there, 2008, 2009, that is just
19 the crop year. Next slide, please.

20 Let me move on to the second part of this
21 presentation, which I think is more relevant to some of the
22 findings of the report. I want to talk a little bit about
23 meeting the Renewable Fuels Standard and the Low Carbon
24 Fuels Standard, and the role of sugarcane and Ethanol in
25 that market. Next slide, please. Here, I think, has been

1 described quite well, so I am just going to make a couple
2 points here, first, this is the famous, or infamous,
3 depending which perspective you have, Renewable Fuel
4 Standard. This is what the EPA has been asked to implement
5 via the RFS2, as they call it. If all goes according to the
6 law, or according to a plan, the U.S. would be having a very
7 large volumetric mandate by 2022, there would be a limit to
8 how much conventional Ethanol or biofuel could be used for
9 that, such the yellow. The blue is the cellulosic biofuel
10 -- notice I am not saying "Ethanol" here, but biofuel, the
11 loss of biofuels, so it does not necessarily have to be
12 Ethanol. And then the bright green, if you can see there,
13 is the advanced non-cellulosic biofuel that most people,
14 including myself, understand would be where sugarcane
15 Ethanol, at least immediately, would meet the target of at
16 least 40 percent greenhouse gas reduction. And then the red
17 is the biomass, bio-based diesel bucket. Just one comment
18 that I think was in the presentations earlier, and this has
19 to do a lot with these very high projections for E85 that I
20 have seen in your analysis, as well as in EIA's. If you
21 presume that the blue is going to be mandated, and that only
22 cellulosic Ethanol would be allowed to meet that
23 requirement, then obviously, if there is no increase in the
24 blend wall, there would have to be a significant increase in
25 E85. Based on what is pretty clear from EPA's analysis, and

1 the reading of the law, they have ample room to reduce
2 those requirements not to be -- in case cellulosic Ethanol
3 is not available. I just point that out because I think
4 time is going to continually look at this issue. I realize
5 it still leaves a lot of uncertainty to the fuel
6 distributors, especially the retailers, but I am quite
7 suspicious of the very high demand for E85 going forward.
8 Then, if we can go to the next slide?

9 Then, if we look at the Low Carbon Fuel Standard,
10 this is sort of a very simplified way of thinking about it,
11 just from the gasoline perspective, but as I think was
12 pointed out by several, according to CARB, gasoline has a
13 carbon intensity in California of about 96 grams of CO₂ per
14 megajoule. The target is to reduce that gasoline carbon
15 intensity to 86 in 2020. And the current calculations,
16 including what I think is an exact rate of penalty for
17 indirect land use of 30 for corn, 46 for cane Ethanol in
18 Brazil, puts the numbers there -- you see corn Ethanol would
19 be actually almost 100 grams, which would be higher than
20 gasoline, and sugarcane Ethanol, in what I think is the most
21 likely pathway that would be coming to California, would be
22 12 + 46, so you are at about 58 there. All that tells you
23 is that, as CARB has developed their calculations right now,
24 it would be very unlikely that corn Ethanol would be used to
25 meet the LCFS, although I do think those numbers will be

1 revised downward over time, I am certainly hopeful for
2 that, on both the direct and indirect impacts, and then
3 sugarcane Ethanol would have an impact. So, if you go to
4 the next slide, actually, this coincides very well with your
5 chart there in the report, but this is my own kind of
6 simulation of, well, what if you could blend 10 percent
7 sugarcane Ethanol in all of California's gasoline, what
8 would that do to meet the LCFS? Well, you basically would
9 get to about 2016 without counting the credits for the
10 preceding year if you blended E10 sugarcane Ethanol, 10
11 percent sugarcane Ethanol, and 90 percent California
12 gasoline. Then, theoretically you could probably use some
13 credits that you have generated in the prior years out to
14 2017, or you could use -- you would then go to an E85
15 scenario. Now, this is a scenario that is just simply so
16 you can kind of get -- I can get my mind around it -- this
17 is not a scenario of how I think it will happen, in large
18 part because we have, I think, a lot of infrastructure
19 challenges and logistics, to say the least, about price
20 going forward. So I really see this as a reasonable, but
21 not likely scenario, if I could say it that way. Next
22 slide, please.

23 So we now are in a situation where you can say,
24 well, Brazilian sugarcane Ethanol would meet not only the
25 federal standard, but the California requirement, and then

1 it is a question of why the volume is there, and can you
2 get them at a reasonable price. Well, first, I think -- let
3 me say in terms of volume, I think that, as I showed
4 earlier, there certainly are the volumes California, you
5 know, faculty and low calculations for me have always been
6 about a billion and a half gallons of Ethanol that would be
7 needed to meet the E10 or so requirement, and then you have
8 got theoretically another four billion gallons or so of the
9 advanced pool in the RFS that I showed about three slides
10 earlier. But those are not mutually exclusive because you
11 can meet the RFS in California, and even if you generate
12 extra RINS in California, you could use those for elsewhere
13 in the state, so theoretically you could even have a
14 scenario where Brazil would need to send somewhere around 3
15 or 4 billion gallons by 2020, or so, and would meet the
16 requirements. So we are not talking about, you know, as
17 some have, I think, incorrectly said, completely depending
18 on Brazilian Ethanol. Now, on the price side, so you know,
19 4 billion gallons, yes, it is a lot, it is more than half of
20 what Brazil produces today, but it is certainly something
21 that we expect over the next five, 10 years, to be a
22 reasonable increase in Brazilian production.

23 The second part really has to do with price, and
24 that is really what this slide is about. It was noted
25 earlier, but Brazil, any fuel Ethanol coming into the U.S.

1 has to pay 2.5 percent at the lower end tariff, plus a
2 \$.54 per gallon tariff. If you look historically, that has
3 really meant about -- for those non-math majors like me --
4 that works out to about a 28-30 percent surcharge on
5 imported Ethanol. And then, to be fair, I think many of you
6 will know, there is a \$.45 per gallon blenders tax credit
7 that the fuel blender gets for mixing Ethanol with gasoline
8 in the U.S. today. And then, if the import of Ethanol comes
9 through a Caribbean country, it is exempt from paying -- it
10 is dehydrated in the Caribbean country, or produced in the
11 Caribbean country, it is exempt from the \$.54 per gallon
12 surcharge. But the effect of the trade policy is actually,
13 for its complexity, it is pretty simple. It is to raise the
14 price of Ethanol in the U.S. market, and not to let that
15 inflated price provide any benefit to the exporter or the
16 importer of the Ethanol into the U.S. So that is why, as
17 you have seen earlier, Brazil, despite the fact that we are
18 very efficient, we have a very low price of Ethanol, much
19 lower than in the U.S., we have not been allowed -- we have
20 not had any significant market share in the U.S. Why?
21 Because ultimately we have to be -- we have about a 30
22 percent barrier in front of us. So, as I look at scenarios
23 going forward for California, if California's demand for
24 Ethanol increases, there may be well some shuffling of
25 Ethanol from Brazil that normally enters through the East

1 Coast, and now we go through the West Coast, but unless
2 prices adjust upward, there is probably not going to be a
3 great increase, unless the tariff barriers get reduced. So
4 this flag, what you see here, is just a simple scenario that
5 we ran at the end of last year, and with the financial
6 crisis we have not tried to re-run these scenarios. But we
7 said, what if at the end of 2008, or in 2008, Congress and
8 the U.S. decided to reduce the tariff to the level of the
9 blender's tax credit -- that is the blue line -- or reduce
10 the tariff altogether, and the tax credit -- that is the
11 green line -- how much Ethanol would the U.S. actually
12 receive from Brazil? Our scenario showed that, if nothing
13 changes, Brazil will be shipping by 2015 a billion and a
14 half, maybe 1.8 billion gallons a year; if there is parity,
15 which actually I think Senator Feinstein has proposed
16 legislation to that effect, you would have that volume
17 increased about 4 billion gallons by 2015, and if there were
18 no tariff at all, in fact, if we treated Ethanol trade like
19 we treat gasoline, Brazil would be shipping upwards of 6-6.5
20 billion gallons of Ethanol per year to the U.S. Now, if you
21 superimposed that on the RFS, which is those bars in grey,
22 and just superimposed that on top of the conventional
23 Ethanol and the advanced Ethanol mandate, I am not including
24 in there the cellulosic, which you will see is pretty
25 clearly -- in the total free market scenario, Brazil would

1 still only have about a one-third market share in the U.S.
2 under the RFS, which is, by the way, most people would think
3 that this is an overly ambitious scenario, but I think it
4 just points to this myth that, if there were no tariff, that
5 all of a sudden that the U.S. would become dependent on
6 Brazilian Ethanol. I think that is far from it. And more
7 importantly, if we do not do this -- and I think this is
8 where I would like to end -- consumers in California are
9 likely going to have to pay a higher price in order for the
10 Low Carbon Fuel Standard to be implemented because, if the
11 only fuel that meets the standard is, at least for gasoline
12 purposes right now, would be sugarcane Ethanol, and if
13 Congress imposes a 30 percent tariff on it, I do not see how
14 -- we are not going to produce Ethanol at a loss in Brazil,
15 sell it at a loss to the U.S. simply because we think the
16 policy is laudable. We do think the policy is laudable, but
17 it runs head-on to the trade policy of the United States
18 which, you know, penalizes a low carbon fuel. So I will end
19 it at that. Hopefully you will have some questions, and I
20 think my e-mail was there on the presentation, on the next
21 slide, if you have any questions for me.

22 VICE CHAIR BOYD: Thank you. This is Commissioner
23 Boyd. While I have got you, I would like to check some of
24 the facts as I understand them and get accurate answers from
25 a knowledgeable person like your self. You said, in Brazil,

1 you offer E25 and E100 to the motorists. Is it truly
2 E100? Because I have been operating under maybe incorrect
3 information that says it is really more like E98. Do you
4 denature with two percent gasoline?

5 MR. VELASCO: No, well, no we do not denature
6 Ethanol in Brazil. We leave that here to the United States,
7 but in Brazil, what I call E100 is hydrous Ethanol.

8 VICE CHAIR BOYD: Yeah, I heard that.

9 MR. VELASCO: And hydrous Ethanol has about 5
10 percent water content. So it would be correct in saying it
11 is really E95 --

12 VICE CHAIR BOYD: All I need is ice-cubes?

13 MR. VELASCO: Yeah, well, when you make Ethanol
14 from cane, you still have a lot of water in it and removing
15 that 5 percent of water from the Ethanol for cars that --
16 for Brazilian flex fuel cars, it is a lot of wasted energy
17 and money, and the car does run on 5 percent water. But you
18 cannot blend hydrous Ethanol with gasoline.

19 VICE CHAIR BOYD: Right. Okay. It is my
20 understanding that the sugarcane cycle is roughly a six-year
21 cycle because initial production and the secondary
22 production. Is that correct?

23 MR. VELASCO: No.

24 VICE CHAIR BOYD: Oh, good. My facts are all
25 wrong.

1 MR. VELASCO: No, you are correct on one point.
2 You replant sugarcane. Sugarcane is a semi-perennial crop.
3 Think of bamboo meets grasses. It looks like bamboo a bit
4 and every time you cut cane, you cut above-ground to process
5 it into sugar and Ethanol, and usually that is a fifth,
6 sixth, seven, eight years you have to actually replant the
7 crop, that is probably where you got the six, seven year.

8 VICE CHAIR BOYD: Okay.

9 MR. VELASCO: Usually, from the moment I plant my
10 cane, I can be producing Ethanol and sugar within a year
11 because it takes about a year for the cane to grow. You
12 only do one harvest per year, but as I think has been
13 pointed out before, we harvest for about six months of the
14 year in Central Brazil, and the other six months of the year
15 the Northeast of Brazil grows cane. We do not store -- you
16 cannot store cane after it has been cut for more than 24
17 hours because it begins to ferment. Actually, for
18 California, think of grapes, you know, it needs to be
19 treated a little bit like grapes.

20 VICE CHAIR BOYD: Okay. Now let me change the
21 subject slightly here. You are quite aware, I am sure, of
22 the very substantial concerns in the arena of sustainability
23 and particularly in California the concepts of
24 sustainability, which are defined by various people in
25 different ways, but nonetheless, you may have heard

1 discussion this morning of the full fuel cycle analysis,
2 or cradle to grave type analyses. It is aimed at greenhouse
3 gases, but it is really applicable to let's just say impacts
4 on the environment, particularly when you are talking about
5 sustainability. So, in California, there is a huge worry
6 about air quality emissions. And I am wondering two things,
7 I am wondering if you would comment on the concerns that
8 some people have about, in Brazil, you burn the fields
9 versus using mechanical harvesting, or there is some
10 percentage of that; and secondly, it is kind of -- what kind
11 of air quality emissions control do you have on emissions of
12 even criteria pollutant from sugar processing plants, or the
13 plants that ultimately produce the Ethanol?

14 MR. VELASCO: Sure. I appreciate the question. I
15 have been in UNICA for about two years now, and from the
16 very beginning we have put sustainability at the top of the
17 agenda. In fact, we are, I think, the only trade
18 association in Brazil now who has, at least publicly so far,
19 called on Brazil to do a lot more as a government, both in
20 terms of combating deforestation and things of that nature,
21 so we believe in a holistic view of sustainability that is,
22 you know, economic, it is social, it is environmental. Now,
23 and so much so that, though we have serious questions about
24 the lifecycle analysis that has been done up to date,
25 including the indirect effect, we have been very clear that

1 we are not questioning the fact that there are indirect
2 effects, but the question of is the magnitude accurate. In
3 terms of your specific questions on the environment, well,
4 first, before the environment, let me talk about just the
5 social aspect of this because it is a critical one for
6 Brazil. We just actually published, and I will be sure to
7 send it to you, a copy, first a full report done under the
8 auspices of the World Bank of the sustainability practices
9 of each Ethanol mill in Brazil, and what we found is we are
10 quite ahead of where we thought we were, both in terms of
11 labor concerns and of that sort, really, you know, providing
12 education to our workers, worker re-training, and that sort.
13 But really, on the air quality issues that you raise, first,
14 one of the reasons that I insisted so much that CARB update
15 their lifecycle analysis pathways for sugarcane Ethanol, was
16 that they presumed that all sugarcane in Brazil is burned in
17 the field. Today, at the aggregate of Brazil, about only
18 one-third of the cane is actually harvested mechanically,
19 one just needs to look at John Deere earnings reports to see
20 how much money they are making from selling harvesters to
21 us, to see that we are changing that practice. And a number
22 of other governmental actions in Brazil and commitments
23 that, by the industry, are basically meaning that sugarcane
24 burning in the field is going to end. It will end in San
25 Paulo, we have a date in 2014, because -- and, in fact, many

1 of us expect it will end much quicker. I would venture to
2 say, because of the separate pathways that CARB did, nearly
3 all of the Ethanol that is going to be coming to the U.S.,
4 certain to California, is going to be coming from mills that
5 have no burning cane, and co-generation of electricity, not
6 because of any other reason other than the fact that,
7 because of -- let's call it carbon credits -- given to those
8 processes will encourage the evolution of the technology a
9 lot faster. With regards to environmental standards and
10 emissions standards for the mills themselves, it has
11 actually gotten much more stringent. I was just last week
12 in Brazil and was talking to one mill, for instance, who
13 told me that, because he was beating the government's
14 emissions targets, which have increased just recently, the
15 government was now talking about raising them again. We
16 have, you know, let's be clear, we are not -- I do not think
17 that Brazil is going to have the exact standard that
18 California does for emission plants, but it does not mean
19 that it cannot meet those. Many of these mills, because
20 they are receiving financing from abroad, whether it is
21 through large banks here in the U.S., or even multi-national
22 institutions, are being required to exceed Brazilian
23 standards for emissions. And I will be glad to submit to
24 you more written comments on that. We have submitted -- in
25 the context of going through the E15 waiver process at EPA,

1 we outlined in our letter there all the requirements of
2 emissions standards for vehicles in Brazil, including those
3 used in Ethanol. And what you generally find is that there
4 is not a significant increase in emissions, generally, in
5 fact, most of the emissions are actually lower with Ethanol;
6 of course, from a CO₂ perspective, a greenhouse gas
7 perspective, those are -- the plants are absorbing the
8 tailpipe emissions, but there is admittedly a slight
9 increase of VOCs, I think, that have been detected, and we
10 are not ignoring that in our analysis.

11 VICE CHAIR BOYD: Thank you. And, yes, if you
12 would submit some more in writing, we would appreciate it.

13 COMMISSIONER BYRON: Mr. Velasco, this is Jeff
14 Byron. I have one quick question and it goes back to slide
15 7. I note that the electricity that you are producing from
16 your byproduct, your biogasse, or whatever it was called --
17 bagasse -- is projecting to increase significantly,
18 certainly at a much faster rate than your production of
19 Ethanol is increasing. So does this mean a number of the
20 Ethanol plants are going back and adding this capability?

21 MR. VELASCO: Correct. Thanks for the question.
22 For brevity, I did not sort of show more details on that,
23 but basically what you have in Brazil, and since we are on
24 the slide there, the figures there are the average
25 Megawatts, this is just a way to kind of compare apples and

1 apples so that, when you are comparing it to a natural
2 gas-fired power plant, roughly in Brazil today, the mills
3 are exporting to the grid about 1,800 average Megawatts,
4 okay? It is going to increase significantly for basically
5 two reason, one, you are seeing a number of mills
6 retrofitting, already a lot of them on their way,
7 retrofitting from low pressure boilers to high pressure
8 boilers. Until about 2002, 2003 in Brazil, sugarcane mills
9 could produce their own steam and power from bagasse, but
10 they were basically prohibited from selling surplus
11 electricity to the grid. Those who know much about Brazil
12 know that Brazil is about 80-90 percent hydro-based
13 electricity, and the government controls that, so they did
14 not really care to have much sugarcane-based electricity
15 competing with hydro or even natural gas. So that is one
16 aspect of it. There is going to be a big increase just from
17 retrofitting of mills with higher pressure boilers. The
18 second aspect of it is that, as we mechanize the sugarcane
19 harvest, like in the state of San Paulo, by 2014, all cane
20 will be mechanized, it is already half of the way there.
21 Sugarcane, when you burn it in the field, you are burning
22 almost a third of the biomass, or the plant, in the field
23 prior to harvesting. That one-third is basically energy you
24 are wasting. As you mechanize the harvest, you will be able
25 to utilize about 40-50 percent of the straw, or also

1 considered "trash" from that you were previously burning
2 the field and bringing it into the mill. So, in essence,
3 you are putting more fuel into your boilers. So in a
4 simplified answer, we will increase it because we will
5 increase the pressure of the boilers to high-pressure
6 boilers, and then increase it because we will, in essence,
7 be putting more fuel, fuel that was previously burned and
8 wasted before. So we think those numbers are reasonable.
9 Of course, if the Brazilian government decided for some
10 reason, which I do not think they will, that they will not
11 allow co-generational power, then we may have a problem.
12 When mills sell electricity to the grid, CARB knows this
13 well, we displaced a marginal power supplier in Brazil,
14 which is natural gas and heavy fuel oil, so that -- from an
15 emissions standpoint, co-generation in Brazil from Bagasse
16 makes a lot of sense.

17 COMMISSIONER BYRON: Okay. Mr. Velasco, thank you
18 so very much for your presentation. I think we could even
19 spend more time on this, but in the interest of time, we
20 have some other presentations to get to, so I think I will
21 say thank you. And, Mr. Schremp, can we move on?

22 MR. SCHREMP: Yes, we can, Commissioner. Thank
23 you, Joel. Thanks so much, and we look forward to both your
24 World Bank Report you are going to forward to us, as well as
25 any other written comments you may have, that would be

1 great.

2 MR. VELASCO: Will do. Thank you.

3 VICE CHAIR BOYD: Joel, this is Commissioner Boyd.

4 One quick question that just dawned on me. You mentioned
5 the Caribbean being exempt, but isn't there a volume cap on
6 the amount coming from the Caribbean?

7 MR. VELASCO: Correct. The cap is 7 percent of
8 U.S. consumption of Ethanol from the previous year, so this
9 year it is 7 percent of U.S. consumption last year, so it is
10 basically this year about 600 million gallons will be the
11 cap of Brazilian Ethanol, hydrous Ethanol that could be
12 dehydrated to anhydrous Ethanol in the Caribbean, and
13 entered duty-free. However, if a Caribbean country produces
14 their own Ethanol from their own sugarcane, there is no cap.
15 And this has been one of the things we have been encouraging
16 them -- I cannot say with a lot of success -- to produce
17 their own Ethanol. Ironically, they would rather -- they
18 make more money selling Rum and sugar into the U.S. quota
19 program than making Ethanol for U.S. consumption.

20 VICE CHAIR BOYD: Okay, thank you very much.

21 COMMISSIONER BYRON: Mr. Tobin, welcome. Please
22 go ahead and introduce yourself.

23 MR. TOBIN: Well, thank you very much.

24 Commissioner Boyd, Commissioner Byron --

25 COMMISSIONER BYRON: And you need to speak right

1 into that microphone.

2 MR. TOBIN: Yes, sir. Commissioner Boyd,
3 Commissioner Byron, thank you very much for the opportunity
4 to come and speak to you. Gordon and I really appreciate
5 the invitation, the quality of the presentations here have
6 just been outstanding, at least for me out here watching
7 you, a tremendous amount of effort and time that has been
8 put on and it is greatly appreciated.

9 COMMISSIONER BYRON: Mr. Tobin, I apologize for
10 interrupting you again, but you are going to have to turn
11 the mic towards you, or speak right into it.

12 MR. TOBIN: I certainly will. A little better?

13 VICE CHAIR BOYD: Oh, a lot better.

14 MR. TOBIN: I am going to talk a little bit today
15 about Kinder Morgan in a very general sense and the way that
16 we do things, our presence here in California. I am going
17 to talk a little bit about what is underway in terms of our
18 investments in infrastructure here in the state, and how we
19 view the state going forward. Ah, shoot -- all that talk
20 about Rum is getting to me here.

21 Okay, just in a very general sense, Kinder Morgan
22 overall is not an old company by any means, we are about 12-
23 years-old, started out of the ashes of Enron, one small
24 pipeline and two terminals, about 12 years ago. Now,
25 something like 25,000 miles of pipelines, 165 terminals

1 across the U.S. and Canada, set up into four basic
2 business segments -- natural gas pipelines, CO₂ -- natural
3 gas pipelines, I will talk about in a second -- CO₂ which is
4 used in tertiary recovery of oil, especially in West Texas,
5 from naturally occurring dome, products pipelines which are
6 generally associated with a commercial pipeline of sorts,
7 and the terminals group, our side. On the terminals side,
8 we handle roughly 600 million barrels of products with
9 throughput annually, about 100 million tons of bulk
10 products, everything from coal, to pet coke, to aggregates
11 and salt. This is the Kinder Morgan network as it exists
12 today. Just a couple of things worth noting on here. We
13 are right in the process right now of finishing up -- and I
14 say this not because it is having to do, necessarily, with
15 California, but it shows how we view things -- we are
16 investing in what is called the REX pipeline, which
17 originates in Western Colorado, and you see that sort of
18 dash brown line that moves all the way across the U.S., into
19 Western Pennsylvania, it is a 1,700 mile pipeline there to
20 do nothing but take natural gas out of the ground in Western
21 Colorado, and move it into eastern markets. This is a \$5
22 billion project undertaken with Conoco Phillips and Semptra,
23 partners that set up in a full take or pay basis, so
24 regardless of what the markets do over the next number of
25 years, this should be taken care of. Trans-Mountain

1 Pipeline, what you see up in Canada, in Alberta there, was
2 set up something around 2005 timeframe, we now move crude
3 out of the oil sands region up in Alberta through the Port
4 of Burnabee in Vancouver, out to far eastern markets, other
5 places, roughly 270,000 barrels a day, we put in an
6 expansion and we should get to 300,000 shortly. And you
7 will also note, of course, that in California we have
8 essentially two sets of assets, first, the remnants of the
9 old Santa Fe Pipeline, which in the northern and southern
10 half of California, distribute the vast preponderance of the
11 commercial pipeline, products pipelines, moving throughout
12 Southern and Northern California, and another line moving
13 from Colton out to Las Vegas, which is called the CalNET
14 line. I should mention on this map, as well, that we have a
15 substantial investment in the State of Texas. One of Kinder
16 Morgan's predecessor companies was called GATX. GATX was
17 set up to reduce the amount of redundant infrastructure some
18 of the big oil companies had in Houston, by allowing them a
19 central point of distribution out to eastern markets. It
20 connects to both the Colonial pipeline and the Explorer
21 pipeline, as well, and again feeds its way up to various
22 markets throughout the east.

23 And with all this investment in infrastructure on
24 the petroleum side, obviously from our side, the Ethanol
25 movement for us was a big deal. Across the U.S., over the

1 last number of years, as you might imagine, we have spent
2 a lot of time and a lot of thought on Ethanol. That 35
3 million barrels in 2009 is roughly 1.5 million gallons or
4 so, and, you know, overall demand right now is 9.5 or 10.
5 It is a pretty substantial amount of product. And we have
6 done this by focusing in on a whole variety of service
7 offerings, for example, we can take in some of the product
8 Joel was talking about, Brazilian product, CBI product, via
9 direct vessel in, in the New York Harbor, in Houston, and in
10 Tampa. We also have a series of terminals that are set up
11 strictly as storage terminals, Chicago and Argo are often
12 used as trading hubs for Ethanol throughout the Midwest.
13 Additionally, we have a series of terminals that are tied to
14 a product pipeline terminal, many of them you see in sort of
15 the Southeast, the Richmond, Washington, D.C. area, are all
16 connected to plantation system which needed investment to
17 allow places like Virginia, North Carolina, Georgia,
18 Alabama, to meet their own requirements statewide. Also, in
19 the Southeast, we do a lot of rail transfer of Ethanol
20 simply by virtue of the fact that you cannot set up a full
21 unit train distribution outlet on a market that really does
22 not demand it, size-wise.

23 Taking all this in total, you have to understand
24 that the amount of time and effort that went into the
25 overall energy transport industry of the last 75 years has

1 been substantial. This network, of sorts, parallel
2 network, for Ethanol has been set up essentially over the
3 last five or seven. That being said, with logistics going
4 on in Ethanol, it has been a little bit challenging. We
5 like unit trains, we think they are a good idea, but as I
6 mentioned earlier, it is very difficult to develop them.
7 The major class one railroads in the U.S. have made a point
8 of going to the Ethanol producers and said, "Look, as you
9 develop your own facilities, please consider the fact that
10 we are not going to agree to take them unless they are a
11 sufficient size." So most of these plants in the Midwest
12 are now somewhere between 100 and 120 cars worth of capacity
13 and they can send a train out every four days or so, and
14 very easy to do when you are on a large patch of dirt out in
15 the Midwest, but very difficult to do when you are trying to
16 take that train in a major metropolitan area like the City
17 of New York, or the L.A. Basin. So much trickier in terms
18 of development and betting there. And, as a result, you see
19 very few places in the U.S. that can actually take a full
20 train of Ethanol. L.A. Basin certainly was the first.
21 There have been a couple in the New York Harbor area that
22 have come about quickly. Baltimore has one now. Dallas has
23 two. And of course, we have some in Houston, as well,
24 various iterations I will talk about in a little bit. We
25 have looked in great detail at the movement of product,

1 Ethanol product via pipelines. As a matter of fact, that
2 REX pipeline that I told you about, the Rockies Express, one
3 of the initial versions of that was actually taking product
4 that was moving through that pipeline, putting it on an
5 additional line to do nothing but handle Ethanol. But
6 Ethanol in a pipe is a very tricky thing. We have run a
7 series of tests to allow ourselves better to understand how
8 Ethanol can be distributed via pipe, and there are only a
9 few conditions where it does make sense. We have taken one
10 right now in Central Florida, and it is the only commercial
11 pipeline that we know of that is moving product of any
12 distance, and it takes product out of Tampa and moves it
13 into the Orlando market, roughly 90 miles or so. But we had
14 no fewer than 31 tasks that were done to that pipeline,
15 which is relatively new, more like a 10-11 year pipeline,
16 which is new in pipeline terms, and spent a good deal of
17 time and money to make sure that there is no possibility, or
18 very very limited possibility for any leaks. So, to that
19 extent, we feel reasonably comfortable to duplicate that
20 across a large segment of the U.S., say, for example, to
21 feed California with a pipeline would be a much more
22 difficult and expensive venture, which is why you do not see
23 a lot of discussion about Ethanol pipes.

24 I did mention that the single car network in the
25 U.S. is fairly vibrant, it is. We are doing it in a number

1 of places. The problem with single car movements of
2 Ethanol is that they are a little bit messy. The U.S. Rail
3 network, unlike some of the passenger networks you would see
4 in Europe, does not run to a fixed timetable and, if you do
5 run short of product, it can be very very difficult to make
6 up, so we see a lot of time and a lot of money being
7 invested in uni-train facilities where they cannot support
8 them as being worth it, at the end of the day.

9 A lot of this has been gone over in earlier
10 presentations, so I am not going to spend a lot of time on
11 some of this. I would say that right now, you know, we are
12 figuring sort of along the lines of what we had seen in the
13 presentations, which is something like a million barrels a
14 day with a demand here in terms of gasoline, which would
15 take what was at a 5.7 percent blend, 60,000 barrels a day,
16 up to 100,000 barrels a day, looking into 2010 and beyond,
17 very much consistent with the numbers that Gordon had shown
18 there. What this means in practical terms is there is a lot
19 of extra Ethanol that will come in to both Northern and
20 Southern California, that has to be dealt with, and it has
21 to be dealt within such a way where there is no too much
22 pressure to put on the existing infrastructure to handle it.
23 Gordon mentioned that we did have a working facility here in
24 Southern California, and that is absolutely true. We made a
25 rail terminal from a company called U.S. Development in

1 2006. At the time, it had been up and going for three
2 years, it sat up in such a way where it runs by 2:16 a car
3 unloading tracks, and it takes its product and feeds it
4 directly into a pipe up to Shell Oil Products, U.S., which
5 is about three miles away. From there, it is distributed
6 via truck all the way across the L.A. Basin, as far as
7 Colton and San Diego, 70 and 100 miles, respectively, so
8 quite a wide distribution network for this facility. The
9 reason it works is we are able to take a fairly substantial
10 amount of product, and I would say a 96-car train, and get
11 it unloaded in less than 24 hours. That involves less
12 pumping time than you might think, a whole lot of switching
13 time, to have it work and make sense. But as it sits right
14 now, sufficient capability exists to handle not only the 5-7
15 environment, or the 7 percent environment we are in right
16 now, to get fully up to 10 percent. We are running about
17 22,000 barrels a day, which is about 925,000 gallons per day
18 on average through this facility, essentially that means 10
19 trains a month, or one every three days. We can go to
20 easily one every two days. We figure a nascent demand would
21 be somewhere in the area of 16-17 trains a month, without
22 too much of a problem. Our program, really, on this side is
23 not ourselves, but what follows up the chain on the
24 distribution network. For example, our partner, Shell
25 Carson, is limited on the amount of trucks that it can

1 release on a daily basis. Right now, they are under
2 permitting and they are trying to get their 150 truck a day
3 limit, which is something around 28,000 barrels, up to 250
4 trucks a day. I cannot emphasize enough how important it is
5 from people like in our business to work with their local
6 communities and their local governing boards to make sure
7 that the needs of the communities are addressed when
8 handling Ethanol. As you may know, there was a fairly
9 significant Ethanol terminal that was put in in Alexandria
10 this year, Alexandria, Virginia, with great amounts of
11 resistance from the local populous. Unfortunately, the way
12 the railroads are set up, they have federal jurisdiction,
13 and they can set up pretty much without being encumbered by
14 city or state regulations, given the federal mandate they
15 have. But it has been a very difficult subject across the
16 U.S. in the handling of Ethanol, and where you put these
17 facilities, and the sensitivities that you have for the
18 community.

19 In the new train facility, we are also looking at
20 investing here, Gordon alluded to it earlier on, this is a
21 facility in Richmond, California, just down the way a bit.
22 Ideally, this would not have been our first choice. We had
23 looked at setting up a fairly significant and robust
24 facility in Martinez, California, right next to the Tesoro
25 Refinery, a beautiful place, nice place to put a rail,

1 certainly out of any sort of population areas that would
2 have given us any difficulty, fully connected to a dock
3 aligned for imports and exports, you name it, but it is very
4 very difficult to make that level of investment with an
5 uncertain regulatory climate, certainly -- it is tough in
6 any environment, and it is certainly tough on that side,
7 that was roughly a \$45-\$50 million project. From our side,
8 we are really dependent upon those who would invest in these
9 operations to make them go, we will not do it sort of on a
10 speculative basis. So option 2, as Gordon also alluded to,
11 a lot of the producers this past year fell into great
12 amounts of trouble financially, and as a result some of the
13 assets that they had in play fell out, this happened to be
14 one of them, and we were able to take this as a fully
15 permitted facility, and set it up in such a way where I
16 think, you know, within the next three or four months, we
17 should be up and going and taking trains. It is not
18 particularly elegant in that it is not connected to a
19 storage or a pipe outlet, really, to speak of. We are going
20 to go rail to truck. But we view this as an interim
21 solution to something that might be a little more robust as
22 legislation becomes a bit more clear, and some of our
23 customers feel more comfortable in making an investment in a
24 long-term facility. There is an existing facility up in
25 Selby today, and Rahul is going to talk about his facility.

1 Investments are underway in various areas, just not an
2 easy thing to do.

3 I am not going to spend a lot of time on this, I
4 think we talked about it quite a bit in the last couple
5 hours or so. We see the same sort of pressures going on. I
6 was with a group of Ethanol producers from the Midwest last
7 week and they are fully convinced that, you know, they will
8 not be shipping Ethanol under current legislation in
9 California 2014-2015 timeframe; it is going to bring about
10 some pressures themselves. Where we see this getting a
11 little tricky on the legislative side is that there are
12 others who felt, or who have greenhouse gas initiatives very
13 similar to California, and we mentioned this Regional
14 Greenhouse Gas Initiative, this is a group of states that
15 have banded together and, in fact, have said, "We think that
16 the California approach is a good one. We are going to
17 follow the path that they have laid out, and we are going to
18 enact it in a very similar fashion." The sort of broad
19 outline of that is that Brazilian Ethanol, as it has been
20 described, becomes a pretty pretty sought after commodity.
21 And there are some questions about how it is that Ethanol is
22 going to be distributed going forward, and whether or not
23 Brazilian Ethanol is going to make its way into California,
24 whether it is going to make its way into Northeastern
25 markets, or whether it is going to make it into other

1 markets, as well. We see that there will probably be a
2 competition of sorts for Brazilian Ethanol, almost as much
3 as to take Brazilian Ethanol and put a bit of a premium on
4 it, and have it traded in a separate fashion. We will see.

5 There are a variety of issues around the logistics
6 that we are looking at of handling Ethanol originating from
7 Brazil, that are interesting. Right now, coming out of
8 Santos, or coming out of San Paulo, you have a couple of
9 options on taking a large vessel, you can take it through
10 the Canal, you can take it through CBI, or you can take it
11 all the way around the Horn, back up into the California
12 market to hit California. All those are a little bit
13 expensive and a little bit challenging. The size of the
14 vessels are roughly 335,000 barrels, sort of six-unit
15 trains, let's call it, and when they arrive, they have to be
16 multi-ported if they are coming in at that size because
17 there really is not the storage infrastructure available in
18 Southern California to take that quantity in product at
19 once. So, as a result, we are looking at other ways to deal
20 with that, which I will talk about in a second.

21 The other thing that we are looking at, as well,
22 as this moves along, there has been talk about E15 and E15
23 certainly not in California, but in Midwestern markets. The
24 fact that they are looking at it indicates that they are
25 essentially seeing the roadmap on what will happen to their

1 participation in the California market, and deciding that
2 maybe they could keep that volume at home, rather than
3 sending it out to the Coast on either side. You know,
4 interesting the way they sort of take care of their own.
5 There are, I think, 1,771 E85 stations in the U.S., right
6 now, 31 percent of those stations are in Minnesota, Iowa, or
7 the Dakotas. Ninety percent of the flex fuel vehicles in
8 the U.S. right now do not have an E85 pump in their Zip
9 Code. So I think, by watching the way that they react to
10 this, I think they view this as sort of a natural resource
11 that they are going to deal with in their own way, which
12 makes this a very interesting scenario for us.

13 We also share the view that Brazilian Ethanol
14 right now is very dependent upon sugar economics and what
15 makes sugar economics go. I heard Joel and we are
16 encouraged by his prospects and what he thinks is going to
17 go on because we think there are real markets right here in
18 the U.S. Gordon sort of alluded to this earlier, we do have
19 a project underway right now -- because of what I described
20 as the difficulty of moving Ethanol to the West Coast, there
21 are a couple of different ways you could go about it -- we
22 have a facility right now in the Gulf called Deer Park Rail
23 Terminal, that we actually picked up about the same time as
24 we picked up Lomita Rail, as well, and it is about a 1,100
25 car spot facility, there is no problem with us actually

1 taking this facility, redoing it slightly, and having the
2 capability of taking product here into low product and to
3 send it out. The way this happens is via a pipeline that is
4 connected to our Deer Park Rail Terminal to the Pasadena
5 Truck Rack. If you can see KM Pasadena out there on the
6 left-hand side of the picture, it is a fairly robust
7 gasoline distribution area right there. Our truck rack is
8 just to the south of it and, you know, if you can get
9 product into this system, you have a pretty good way of
10 getting out. But the way the legislation is working right
11 now, and the way that we are viewing it, and what some of
12 our customers are telling us, you can envision a situation
13 where we would actually take in a trainload of corn Ethanol,
14 put it into the existing distribution system, load that same
15 train back out with Brazilian Ethanol, out to the West
16 Coast, and do sort of a three-legged stool on it. Where it
17 gets very difficult for us, in talking to some of our
18 stakeholders, is around the idea of segregation -- does the
19 Ethanol have to retain its identity by the time -- because
20 Ethanol, as far as we can tell from a chemical standpoint --
21 is Ethanol, whether it comes from an algae source, whether
22 it comes from cellulosic, whether it comes from sugarcane,
23 whether it comes from anything else, chemically it is very
24 much the same. But obviously, having the footprints that it
25 does, and the values that are associated with the various

1 origin points, makes the idea of segregating product a
2 little bit tricky. For us, that means capital, a capital
3 investment of sorts to make sure that the product itself is
4 housed in the same -- in a way that allows it to retain its
5 identity. So we are looking eagerly to see how all that
6 transpires. For right now, the customer that we are talking
7 to here is keen on optionality, as they usually are, just
8 making sure that whatever investment decisions they make,
9 they will be able to move forward with them later on.

10 So to sum up a little bit, I guess from our side,
11 my Management has a fundamental belief in the RFS. I think
12 you have to have a fundamental belief in the RFS going
13 forward. If there is one thing you can believe in, that
14 would be it. And in having that belief, you know that
15 certain things are going to happen. We think in California,
16 it will probably sort itself out in ways that we really
17 could not understand right now, but that might work. In our
18 business, we cannot go out and speculate, there is within
19 our shop very few investments that are made without a firm
20 customer commitment behind them. No Field of Dreams out on
21 our side, for sure. We are generally going after some of
22 the majors because investing with Ethanol producers,
23 especially in the last couple years, has been very very
24 tricky, and not something -- not a place you really wanted
25 to be. We like the idea of working with the rail carriers.

1 There is a tremendous amount of flexibility in that work
2 and it can allow us to grow in a way that makes sense. We
3 have got a lot of experience in handling a lot of these
4 products, and I can tell you, as the volumes increase, the
5 experience in handling the product is very very important.
6 And, of course, from our side, a clear bid on regulation and
7 a good understanding on where you are going to go just
8 really makes our life a lot easier.

9 So, again, if there are any questions. Thanks
10 very much.

11 VICE CHAIR BOYD: Thank you, that was very
12 educational.

13 COMMISSIONER BYRON: Agreed. Mr. Tobin, thank you
14 very much. And I think we will forego questions and try to
15 get back on schedule.

16 VICE CHAIR BOYD: I did learn -- I had no idea you
17 rose from the ashes of Enron, that was a factoid I did not
18 know.

19 MR. TOBIN: Actually, yeah, Rich Kinder was Ken
20 Lay's right-hand man, and left in '97 because he did not
21 like the way the business was going.

22 VICE CHAIR BOYD: Good.

23 MR. IYER: Thank you so much for the opportunity
24 to address the -- oops -- to address Windows XP.

25 COMMISSIONER BYRON: That is all right. Please go

1 ahead and introduce yourself while you are --

2 MR. IYER: Sure. My name is Rahul Iyer. I am a
3 Co-Founder and Chief Strategy Officer of Primafuel, a
4 California based biofuels technology and infrastructure
5 company.

6 COMMISSIONER BYRON: Good, welcome.

7 MR. IYER: Thank you. I mention that only because
8 I will be making some comments towards the end of my
9 presentation on technology and how it is, in fact, relevant
10 to this infrastructure conversation that we are having
11 today. So I intend to recap the comments that myself and my
12 company shared at the last meeting a few months back, prior
13 to the draft publication of this report, just to remind you
14 of where we are coming from and our thoughts on this topic,
15 and then I would like to do a bit of an overview or a
16 review, if you like, of the draft document and points that
17 are made in the document that we think are critical to be
18 either emphasized or retained into the final version of the
19 document. And I would add a third item to this agenda in
20 that I would like to add a few words on energy security
21 technology and infrastructure.

22 So to recap last time, Primafuel spoke about one
23 of our developments, a low carbon fuels bulk liquid terminal
24 project that we have been developing for some time now at
25 the Port of Sacramento, just on the other side of the river

1 here. We believe, now supported in large part by this
2 fantastic report put out by the staff here, that California
3 is in desperate need of a significant amount of bulk liquids
4 infrastructure associated with renewable fuels. And most
5 importantly, having a lot of multi-level flexibility, marine
6 terminal access, rail, highway, etc. It is precisely those
7 issues that drove us to develop this terminal project, which
8 has now come to be the first marine-based bulk liquids
9 terminal, fully permitted in the State of California, almost
10 a quarter of a century, 24 years. There has been a lot of
11 discussion about how difficult it is to develop things in
12 California, it is true, it is difficult to develop things in
13 California, but it is not impossible. And I believe that
14 there are two distinct responses one can have to a
15 challenging business environment, one is to give up, and the
16 other is to get creative and try harder. We pursued the
17 latter strategy, I think, with some degree of success.

18 Previously in the discussion, it was noted that
19 the terminal is permitted for about a million barrels of
20 storage and that translates into roughly 400 million gallons
21 of throughput, if you like, biofuels, on an annual basis.
22 One of the things I would like to point out that maybe is
23 not mentioned on this slide is that we were very diligent in
24 the way that we developed this project, particularly on the
25 permitting and entitlement side. Chiefly, we were focused

1 in on flexibility. Again, not just in terms of the
2 physical modes of transport, but also in terms of
3 operational flexibility. One of the things we know for sure
4 with respect to AB 32, the Low Carbon Fuels Standard, and
5 RFS2, is that it is extremely difficult to predict to the
6 gallon what kind of fuels will be used in the state, to what
7 degree, where it will come from, and so forth. What we know
8 is that trade flows will change and that the markets will
9 need to be considerably more dynamic. In fact, this is not
10 an accident, this is very much by design. The Air Resources
11 Board has designed the Low Carbon Fuel Standard to create a
12 more dynamic and competitive market, whereby the folks that
13 need to comply, the oil makers and so forth, will be able to
14 make the most cost-effective decisions on the lowest carbon
15 fuels that they are going to bring to the California
16 marketplace. That means that infrastructure has to get
17 considerably smarter and considerably more flexible. For
18 that reason, we permitted this facility not to be an Ethanol
19 terminal, or a biodiesel terminal, rather, we permitted each
20 individual tank on vapor pressure and toxicity requirements,
21 or limits, therefore giving an operator flexibility in what
22 kinds of fuels they might store there, including biobutanol,
23 should that come to pass, and other molecules like that.

24 I would also add that we have created the ability
25 here within our permitting to distribute E85 directly from

1 this bulk liquid terminal, which is different than most
2 bulk liquid terminals that do no real blending at all, and
3 so being able to distribute or provide the Sacramento region
4 with E85 straight from bulk liquid terminal further reduces
5 cost and increases, hopefully, the economic availability of
6 E85 to this region.

7 Again, I think I mentioned some of this on the
8 previous slide, but some of the projections that we shared
9 at the last meeting indeed are supported by some of the
10 conclusions in this draft document, we are quite pleased
11 about that. The upshot is lots more new fuels need
12 infrastructure, that is pretty obvious.

13 I ended the last presentation with a rather bold
14 request, if you recall. We asked that the Energy Commission
15 be forthright and assertive in its demands of the industry
16 to really explain to not just the government, but to
17 consumers how industry is going to respond and meet these
18 very very aggressive targets set up by the Legislature vis a
19 vis AB 32. And I am quite pleased to say that we are very
20 satisfied with the tone in this draft report, a tone that we
21 think provides the right level of seriousness about the
22 challenge before the State of California with regards to
23 fuel availability and infrastructure. So, again, to recap
24 that thought, we believe strongly that the staff at CEC
25 should be extremely proud of the draft report in its current

1 state. It is very well supported. There is a lot of
2 fantastic data in it, and I really hope circulation is broad
3 and wide because it is a very actionable document, if one
4 cares to study it. And, again, the tone of urgency that is
5 communicated in this document, we think, is good. It is
6 responsible. It is not *The Scream*, so to speak, as we heard
7 earlier today, but it is appropriate and we think that it is
8 urgent. In fact, this kind of development, not only of
9 infrastructure, but of new technologies, must continue at a
10 fairly aggressive pace if we are going to meet these
11 regulations.

12 Now, I will hit a few different topics, I will not
13 read the quotations out of your own report because it is
14 obvious that you have gone through it in great detail, but I
15 will highlight sort of the upshot and some of the take-home
16 messages. The work that was done in the report to highlight
17 the impacts of the renewable fuels standard, the federal
18 renewable fuels standard, Phase 2, on California's
19 marketplace is really quite critical, the upshot being, of
20 course, that RFS2 really does drive a significant volumetric
21 change of the use of Ethanol in the State of California, not
22 just Ethanol, of course, but other advanced biofuels
23 including biodiesel. And I think the evidence is well
24 supported and I do not need to beat that topic any harder.

25 On the Low Carbon Fuel Standard, there is a lot of

1 work that was done in this particular report on various
2 scenario modeling based not only on federal numbers, but on
3 Air Resources Board's own numbers vis a vis the performance
4 of various low carbon fuels. The upshot here, I think, is
5 very important to understand, that the Low Carbon Fuel
6 Standard does not accidentally change the trade flows and
7 the types of fuels that we use in the State of California,
8 it is intended to do exactly that. It is intended to create
9 new more competitive marketplaces for our transportation
10 fuels. And so should that create a new dynamic, a new
11 incentive to use Brazilian fuels in California, well, then
12 that is exactly what will occur. It is not by accident, it
13 is quite by design. Should the United States adopt newer
14 technologies to produce even lower costs and lower carbon
15 fuels, then surely those fuels will find their way into
16 California, as well. It is precisely this dynamic market,
17 which is going to call for more dynamic and smarter fuels
18 infrastructure in the state.

19 There has been a lot of discussion about the Low
20 Carbon Fuel Standards, slightly less discussion around
21 Reformulated Gasoline Standard in California, because that
22 certainly impacts the state's fuel use dramatically, as
23 well. We view the Reformulated Gasoline Standard very much
24 as putting boundaries on what can and cannot be used as
25 compliance tools in the state for carbon reduction. And I

1 think there has been a lot of work done here and
2 ultimately we think the upshot is that you have got E10 in
3 the State of California for the foreseeable future, we do
4 not think we are going to get to an E12 or an E15 very soon
5 in California, we know that it took a few years to just get
6 the air shed models done for E10, and some I would argue
7 that are not quite done yet, getting to E15 in the next
8 couple of years would be extremely challenging and unlikely.
9 As a result, we think E10 is probably a low blend ceiling in
10 California for the mid-term, at least, but E85 becomes the
11 major compliance tool with regards to the Low Carbon Fuels
12 Standard in California, with affective gasoline in the short
13 and medium term. Looking ahead, lots of exciting
14 developments on the radar, we will see where the
15 technologies go. But, in short, that is the impact of the
16 Reformulated Gasoline Standard.

17 Now, the draft report does address, obviously, the
18 importation of blending infrastructure in California. I
19 think, again, the upshot is that we need a lot more
20 flexibility in the state. While there has been investment
21 made in unit train infrastructure, as we heard from Kinder
22 Morgan a moment ago, in California, much of that has been
23 done in a piece meal fashion, not part of a larger, more
24 comprehensive effort to upgrade California's capabilities.
25 That does not mean that it does not work today, it does work

1 today, but it works almost, if you like, beside itself.
2 California does not have a very coherent biofuels
3 infrastructure, it is a pastiche of small train unloading
4 facilities at blending terminals, a couple of pseudo unit
5 train facilities, and one fully functional unit train
6 facility in L.A. The reality is that California needs a lot
7 more flexibility, it has very little in the way of multi-
8 modal infrastructure to bring in these biofuels, whether
9 they are produced in the state, or in the Midwest, or
10 offshore. So that is where I will leave that commentary.

11 A point on crude oil, which is not particularly
12 relevant prima facie to the topic of biofuels, but in fact
13 it is with regards to marine terminal storage. A lot of
14 folks in the business are under the impression, at least
15 theoretically, that crude oil tanks can certainly be swapped
16 out and they can store some biodiesel on one season, and
17 store some Ethanol in another season. While technically
18 that may be true, the reality is that California already has
19 a significant shortage of crude oil storage on the marine
20 side. And so the likelihood of swapping out crude oil
21 storage for storing another competing commodity is pretty
22 unlikely, purely on economic terms. It is unlikely that
23 that would occur. And as a result, we think new multi-modal
24 infrastructure is required, or at least expanded capacity.
25 One point here that the report makes early on in the draft

1 is an allusion to a project at the Port of L.A., the Berth
2 408 project to expand crude oil storage. Now, that project
3 has been going on, I think a little more than four years
4 now, maybe more like six or seven years. Millions and
5 millions of dollars have been spent just attempting to get
6 permits in place. They are still not in place. So the
7 question you have to ask yourself is, if we need the
8 equivalent of one new bulk liquid terminal in the state of
9 California every two years to meet these Legislative
10 requirements, then at least one or two of these need to get
11 permitted every year, and that has not been happening for
12 about a quarter of a century, so we have got quite a backlog
13 of projects that need to get built. I am not asking for
14 permitting requirements to get softened, rather, I am asking
15 for industry to get on the horse and start moving a little
16 bit quicker.

17 So a few suggestions before I get on to my
18 conclusions. As I mentioned, I think the findings in this
19 report, or at least some of the data, are mission critical,
20 not just the Legislators to understand to make smarter
21 policies, but also for industry to really really absorb.
22 The challenge, unfortunately, is that most folks that are
23 out there in industry do not have either the time, or the
24 inclination to read what is essentially an academic report
25 at this stage. And so, if I could make some suggestions, I

1 think that there are multiple subsectors of the fuels
2 marketplace that are impacted by this kind of a report, I
3 think it would be really really interesting if Executive
4 Summaries of the report could be generated for each of these
5 subsectors. I do not mean just a half page abstract, I mean
6 a two- or three-page bulletized exec summary with real data
7 in it for each of these subsectors, be it biofuels, or crude
8 oil, what have you. And I think empowering industry to
9 virally distribute those executive summaries will help in
10 the CEC achieving its goal of sort or raising the level of
11 dialogue. That is one. The second is an idea that really,
12 I think the Air Resources Board has demonstrated quite well
13 in its development of the Low Carbon Fuel Standard, which is
14 really creating a roundtable environment where sectors can
15 get together on an industrial basis, on a commercial basis,
16 and have discussions amongst themselves under the auspices
17 and under the guidelines presented by the regulatory body,
18 in that case, the Air Resources Board. I think it would be
19 interesting if the Energy Commission were to actually host,
20 if possible subsector roundtable discussions of the final
21 document and to see what kind of debate can actually be
22 spurred. And I think that may very well provide enough
23 impetus to get certain projects off of the back burner and
24 on to the front burner.

25 So with that, I would like to just add a couple of

1 thoughts which were not on the agenda about energy
2 security technology and infrastructure. We heard earlier
3 today about energy security and we heard that some of these
4 policies may be promoting the importation of someone else's
5 Ethanol over domestic gasoline, and all of these other
6 issues, and that is all very important discussion to be had.
7 I just wanted to point out that energy security is not
8 necessarily a question of domestic supply, or domestic oil
9 versus imported oil, it is really a question of functional
10 competitive marketplaces. And the reality is that crude oil
11 based transportation fuels have a corner on the
12 transportation market in excess of 98 percent of the
13 marketplace, and that does not give Californians, or anyone
14 else in the United States, a real choice either at the pump,
15 or when they buy their vehicles. And that is a lack of
16 energy security. Creating an environment that is more
17 competitive and give ultimately consumers more choices is
18 energy security, irrespective of where those fuels
19 ultimately come from. So that is one point on energy
20 security. Second on technology, I think we heard some
21 inconsistent messages, or internally inconsistent messages
22 today that I would like to make comment on. We heard that
23 there are lots of technologies to find more crude oil and
24 explore it and develop it more sustainably, and there is no
25 doubt about that, that is absolutely true and I would not

1 contest that. But at the same time, there are a whole
2 host of technologies to produce renewable fuels and
3 renewable electricity, and so on and so forth, as well. And
4 I think what we need to maintain here is an open mind, that
5 indeed if we create marketplaces that are truly competitive,
6 and rules that are understood, that you can create an
7 environment much like the Low Carbon Fuel Standard is
8 intended to create, in which there is real competition
9 ultimately resulting in a real choice for consumers.

10 Commissioner Boyd, you asked the question earlier, does the
11 Low Carbon Fuel Standard provide a vehicle by which E85
12 might be adopted in higher concentrations in California.
13 Now, I would submit, if the rules are created clearly and
14 plainly and enforced properly, I would say absolutely. The
15 Low Carbon Fuel Standard is simply an attempt to price in
16 the externality of the climate crisis into every gallon of
17 fuel and ultimately that should result in a price premium
18 for lower carbon fuels. If that benefits Brazil in the
19 short term, that is fine; ultimately, it will result in
20 producers becoming more efficient, distributors becoming
21 more efficient, and everyone up and down the supply chain
22 worrying about their carbon footprint, which is precisely
23 what this type of regulation is intended to do. The
24 challenge now is, can California develop an environment in
25 which the same embracement of change that has been occurring

1 along the technology side, can happen on the
2 infrastructure side, a world that is generally considered
3 boring and old and made out of cement and steel and other
4 boring stuff, no fancy new molecules and enzymes on that
5 side of the fence? The reality is, is that I think the
6 creativity and passion that has been harnessed in California
7 to develop the technologies for fuels, and batteries, and so
8 forth of the future, have to be fostered also on the
9 infrastructure side of this equation. And to the degree
10 that the Energy Commission can foster that kind of
11 creativity, I think California will come out better for it,
12 not only the policymakers, but the citizens more generally,
13 and as a California native, I believe that quite strongly.
14 So, in any case, thank you for that. My contact information
15 is on the slide. Please have a visit of either one of our
16 websites, or give me a call or an e-mail if you should have
17 any questions. We fully intend to provide more detailed
18 responses to the draft report in the coming days with a
19 little bit more quantitative analysis. Thank you for your
20 time.

21 VICE CHAIR BOYD: Thank you very much. Very
22 interesting, intriguing, stimulating, even, suggestions. We
23 appreciate it.

24 MR. IYER: Thanks.

25 COMMISSIONER BYRON: Agreed. Some good

1 recommendations. We will certainly consider them. Thank
2 you for being here.

3 MR. IYER: Thank you.

4 MR. PAGE: Commissioners, we have had a request
5 for an addition to the agenda from Southern California
6 Edison, Felix Oduyemi would like to make a presentation if
7 that is acceptable to you.

8 VICE CHAIR BOYD: Very acceptable. Now you
9 eliminate from my conclusion, "Where is electricity?"

10 MR. PAGE: Okay, well, good.

11 MR. ODUYEMI: Good afternoon, Commissioner Boyd,
12 Commissioner Byron, and those of us who have been here for
13 the whole presentation. I am really really glad that you
14 allowed me to speak. Thank you very much.

15 COMMISSIONER BYRON: Please introduce yourself.

16 MR. ODUYEMI: I am Felix Oduyemi, I am with
17 Advanced Technology at Southern California Edison. I worked
18 specifically as the Manager for Electric Transportation. My
19 first observation when I read the report was that we did not
20 develop electricity as a transportation form, but have since
21 spoken to staff, that was just an early idea they are
22 working on, they are going to be including electricity as a
23 transportation form. So my original reason for being here
24 is not as [inaudible], but I have other issues to cover.

25 You also have as part of this report, the overall

1 report, IEPR, the Smart Grid. And we look at electric
2 transportation as a component of a Smart Grid deployment
3 strategy, so in discussing infrastructure, we have to
4 discuss infrastructure in the context of not just having a
5 plug -- I have a whole bunch of plugs around this room and,
6 yes, I can bring my electric vehicle and actually plug it,
7 and it will be able to work. But long-term, that is really
8 not going to work for us because, if our projections are
9 correct at Southern California Edison, we have about 16
10 percent of our penetration for electric vehicles, and may
11 not be [inaudible] territory by 2020 will get by with
12 electricity. So 16 percent, that constitutes about 11
13 percent of our load, it is a significant amount of load that
14 we expect to devote to electric transportation in 10 short
15 years. And so the generation aspect of the equation is not
16 what we are concerned about, we are more concerned about the
17 distribution, as well as renewable integration aspects of
18 the equation, and those are the ideas that I would like to
19 cover today.

20 When I look at transportation in the future, I
21 look at this chart, and I look at my car, I can actually
22 become an Energy Storage system that is not just providing
23 energy to drive my car, but it can actually provide energy
24 to my grid. But that technology has yet to evolve. So over
25 time, we need the Energy Commission to help us with the

1 necessary research to make this happen. We are developing
2 some research for Energy Storage systems. We are also
3 looking at the same battery that we have in that vehicle is
4 going to be deployed at wind farms to become part of our
5 renewable integration program. So this Commission is going
6 to be very very instrumental in helping the utilities
7 actually optimize utilization of resources, as we continue
8 to deploy Smart Grid.

9 I will look at three key areas, and this is going
10 to be my last slide. I have a whole bunch of them, but I am
11 not going to go beyond this slide because we are running out
12 of time. We look at three legs of this tool as we are
13 thinking about deploying electric transportation into the
14 grid, and I look at distribution system readiness, effective
15 load management, and renewable integration. Those will be
16 the three legs we have to consider as we introduce more
17 electricity to become a transportation fuel. When we do
18 research and we want to deploy public, for example, charging
19 stations, there is a lot of debate with so many of my
20 colleagues, what should this look like? And what will be
21 the impact of that? I am more interested in the impact of
22 that public charging infrastructure on my distribution grid
23 because I still have to provide the electricity to my
24 customers. And so if we deploy our own type of technology
25 or we check the vehicles at your own time, it will probably

1 cost you a whole bunch of black-outs, we do not want that
2 to happen, and we do not want utilities to also have
3 stranded investments, simply build an infrastructure that
4 will not be utilized is really not a very wise use of money.
5 So I take an electric car, you are going to have charging
6 facilities in your house, and charging facilities in your
7 workplace, and therefore, if you have level 1 or level 2
8 charging at home and at your workplace, the way you are
9 meant to deploy level 1, level 2, or level 3 charges as
10 public infrastructure. When you do your math correctly, we
11 may find out that it pays for us to simply do level 3
12 charging when we consider public infrastructure because it
13 should be able to charge whether it is 1, 2, or 3. You just
14 want opportunity charging. I have not completed doing all
15 the analysis, but we intend to do it. But at the end of the
16 day, I am going to have in a city like Santa Monica a whole
17 lot of electric vehicles and we want them to charge off-
18 peak. We are going to be encouraging them to, before
19 charging these vehicles, to later and later in the day.
20 That way, we do not impact our existing peak at about 16:00
21 hours. Now, you get home and you start charging your car at
22 17:00 or 18:00 hours, and I have a spike in my system. You
23 [inaudible] down the system if we do not develop the
24 necessary communication system that will allow us to
25 sequence the charging so that we can level our load. So we

1 have to look at the electric transportation in terms of
2 the communication technologies that we are required to allow
3 us to spread out the charging of the load. We might bring
4 more damage to our distribution system. So whether there is
5 public charging, or workplace charging, or residential
6 charging, we need to look at my column 2 in terms of the
7 vehicle communications and standards that will be required
8 to integrate this into our grid in a way that we can
9 actually manage the load effectively, to help us to achieve
10 a better load factor. I need to look at my computer systems
11 in the back office to be able to do the right communication
12 in terms of billing, in terms of moving electricity from the
13 vehicle to the grid, or from the grid to the vehicle, or to
14 do whole area network. So those times of Smart Grid
15 technologies will need to be considered as we consider
16 electric transportation and deployment. So I am not just
17 here to tell you that we do not have adequate electricity --
18 yes, we do have abundant electricity, but we do not have
19 adequate technologies to actually optimize the utilization
20 of this technology and the utilization of the resources that
21 we already are paying for as a state.

22 And I look at my third block of area that we are
23 focusing on at Edison, which is the renewable integration.
24 Since 1896, the difficulty we have had as a state, or as a
25 country, is that electricity has no color, I mean, you turn

1 it on, you have to use it, we generate it, and it goes.
2 Today, we generate so many Megawatts of power, I do not want
3 to say how much, from many windmills and those windmills,
4 they operate 24/7, most of the time they do not generate
5 much, but at night time when we do not need the electricity,
6 they blow like hell, and now we have all this energy at
7 night time, I have to sell them to some other sources for
8 pennies on the dollar, and so if I am able to start that
9 energy and actually deploy it as I need it, and I use the
10 same technology that I have in the electric vehicle, I can
11 make a bigger size of that, put it in my wind farm, start
12 the energy, and then put it back into the grid at 4:00 p.m.
13 when I actually need the power. It makes a whole lot more
14 sense; however, we are going to need the Energy Commission
15 to help us plead the case that renewable integration into
16 the Grid should be considered a compliance option when we
17 look at RPS compliance. Today, we are 20 percent
18 requirement by 2010, we may be going to 33 percent by 2020,
19 we are not sure yet, I know there are a lot of Bills in the
20 Legislature requiring that, but if we can do better by
21 integrating battery technology or other energy saving
22 technology, NIG storage technologies, into renewable
23 generation assets, that way we can then count the useful
24 generation, not just generation that we produce and we just
25 allow to go to waste, they would count it as meeting our

1 renewable standard. I know I have so many other slides I
2 would have loved to show you, but I will not waste my time
3 on that, but if you can bear with me, by 2015, this is our
4 projection in our service territory, and we did a lot of
5 scrubbing of this data. I am expecting about, oh, 160,000,
6 maybe 161,000 plug-in hybrid electric vehicles and about
7 77,000 BEV's by 2015, that is just six years away. If I
8 allow all of this in my system without the necessary
9 communication technologies to allow me to shift the load in
10 a way that it will not bring my power system down, we will
11 have some challenges. We do not want to have those
12 challenges, and we are going to need your help to work with
13 the CPUC to allow us to send the right price signals to our
14 customers so that, 1) they will be allowed to charge off-
15 peak, give them special rates for charging off-peaks, but
16 also give us the control so that we can manage the load in a
17 way to optimize utilization of our Grid. Thank you very
18 much.

19 VICE CHAIR BOYD: Thank you, Felix. I really
20 appreciate you pushing the point and getting on the agenda.
21 Just last week, Felix and I were at the plug-in hybrid
22 electric vehicle symposium conference in Long Beach, and
23 extensive discussions of some of the subjects you heard here
24 today. This agency created and sponsors a plug-in hybrid
25 electric vehicle research center at UC Davis, it has a

1 research committee advisory to that group in which we
2 discuss a lot of these issues -- Smart Grid, the secondary
3 use of vehicle batteries for this energy storage question
4 that is coming up, and Commissioner Byron and I, being the
5 Electricity and Natural Gas Committee, have had lots of
6 discussions in that committee forum on energy. All of this
7 integrates together as part of the system that has to
8 support whatever forms of transportation and electricity we
9 have in the future. So your point is a very good one. We
10 will certainly take into account all of your slides and we
11 definitely will have electricity in the final report as one
12 of the major alternative transportation fuel sources for the
13 future. So thank you for being here.

14 MR. ODUYEMI: Thank you.

15 MR. SCHREMP: Good afternoon. I am Gordon
16 Schremp, Energy Commission staff. I have yet another
17 presentation. Not as many slides, this is my first one, I
18 will go a little bit faster.

19 The subject matter is, instead of renewables, it
20 is traditional transportation fuels, petroleum-based
21 gasoline, diesel, and jet fuel, and our analysis and outlook
22 on what we see as both exports of petroleum fuels to the
23 neighboring states of Nevada and Arizona, via pipeline, as
24 well as imports of each said fuels, via marine vessels and
25 marine importing infrastructure. Or, as the case may be,

1 marine exports from our analysis.

2 So we are an, I guess, integrated system, if you
3 will, interdependent. California is essentially like a hub
4 on the West Coast. We are the predominant supplier to
5 Nevada and now a little bit less of a supplier to Arizona
6 due to some changes, additional supply from the east. So we
7 went through sort of a stepwise set of analyses to determine
8 what kinds of changes in our trends for both pipeline
9 exports and marine imports may occur over the forecast
10 period. So, first of all, we do some demand projections for
11 Arizona and Nevada, that is because we supply fuel to those
12 states via pipeline. Secondly, we then determine what level
13 of pipeline exports will go to those states from California.
14 Well, Nevada is pretty simple, there is only potentially one
15 pipeline at this time to Northern Nevada, and one pipeline
16 or a couple pipelines to Southern Nevada. But Arizona is
17 supplied from two different directions, so we make some
18 assumptions in there, and I will talk about that in a little
19 bit. Third is, we assume some level of refinery production
20 change due to "refinery creep," Mr. Sparano's favorite term,
21 and we only have that in one of the cases this year, the
22 same in their crude oil assessment that refineries over time
23 will process a little bit more crude oil moving forward, as
24 they have done so historically. And then, finally, looking
25 at our demand projections, and I used the revised gasoline

1 demand projections, not the initial ones, Malachi, of
2 percent, but the ones that are impacted by RFS2 compliance,
3 so they are lower than Malachi's number. And so we look at
4 how all of that works out over time in changing the level of
5 imports that have come through our marine terminals.

6 So this is the Southwest system of Kinder Morgan,
7 and just to highlight the two pipelines going up into Las
8 Vegas, some [inaudible] system, there is a project for a
9 third line that has been permitted, and I will talk a little
10 bit about that. And then we have the main west line that
11 goes all the way into Phoenix, and then there are
12 essentially two lines that come in, the one terminating in
13 Tucson, the other carrying all the way into Phoenix from the
14 East, supplied by refineries in West Texas, and even
15 refineries in the Gulf Coast via the Longhorn Pipeline
16 connection to the East line. So how do we figure those out?
17 We assume that there will be a resurgence of demand, jet
18 fuel, gassing, diesel, after the U.S. long recession comes
19 to an end and some economic recovery does occur, so we do
20 see some demand growth coming back, especially for diesel
21 and jet fuel, as is the case in California. And we think
22 that there will be additional exports via the pipelines.
23 There is one scenario we did examine, and that is a new
24 pipeline originating in Utah, and terminated in North Las
25 Vegas. That is the UNEV pipeline, and that will reduce the

1 demand for pipeline exports to Nevada, and I will show you
2 what that looks like. So like I said, Nevada, about 100
3 percent comes from product originating in California or
4 passing through California on into Nevada. Arizona, though,
5 has been changing the amount of fuels coming out of
6 California, about 55 percent in 2006, but dropping down now
7 to 35 percent in 2008. Well, that is because the east line
8 expansion was completed, additional product was flowing in
9 Longhorn pipeline, and coming all the way from Houston into
10 Western Texas, and connecting to the East line. So that
11 tells us that the marketplace supply options, economics of
12 pipeline delivery, and timing were such that the market
13 wanted more product to come from the East, rather than the
14 West. So we believe that when the system gets back to a
15 more normal circumstance, and I mean part of that system is,
16 as you are well aware, Flying "J" declared Chapter 11 right
17 before Christmas 2008, part of that business changed and
18 restructuring -- the changing hands of some of these assets,
19 one of them is the Longhorn pipeline, which I believe has
20 now moved into the hands of Magellan, and someone can
21 correct me if I am wrong. So we believe that, going
22 forward, that the Longhorn pipeline will have sufficient
23 capital to resume more normal operations and maybe even
24 increase the amount of fuel coming from Houston and going
25 into West Texas and into Arizona. So time will tell,

1 certainly.

2 So we look at these systems and we made certain
3 assumptions about which direction the product will come
4 from, and we think there will be a preponderance of product
5 coming from the East side, into Arizona. So the benefit, if
6 you will, of reduced pipeline exports from California is
7 what we refer to as "indirect supply," well, that means the
8 refiners, for example, have more blending components they
9 can use to produce California gasoline, rather than Arizona
10 cleaner burning gasoline, or Nevada, LVBOB, so that is, I
11 think, good for supply perspective. There certainly has not
12 been a need for that with the tremendous drop in demand for
13 both gasoline and diesel fuel in California, so there has
14 been a respite, but at the same time, having said that,
15 there has been the loss of a refinery, and that is the big
16 west of California, a Flying "J" subsidiary that is now idle
17 because of these Chapter 11 proceedings. So a refinery is
18 not operating, that is a loss of supply, but only because of
19 the big decrease in demand for gasoline, diesel, and jet
20 fuel that the system has been able to accommodate rather
21 easily this time, but we anticipate that that refinery is
22 going to come back in operation some time in 2011 at the
23 latest, in our analysis.

24 So what does the demand look like in Arizona and
25 Nevada? Well, this time through, for both -- for jet fuel,

1 we used the most recent FAA forecast, and these are
2 enplanement activities, passengers boarding planes, by
3 individual airports. So using those enplanement forecasts
4 for the Reno, McCarron Airport, Las Vegas, Arizona, Tucson
5 Airports, in conjunction with changing fuel economy
6 improvements in moving people via jet and freight, we have
7 come up with demand forecasts for jet fuel that shows an
8 increase over the forecast period, and we only use one jet
9 fuel demand trend, we do not have a low and a high. Diesel
10 fuel, we have a low and a high, similar to -- we use, in
11 fact, the exact scenarios from EIA in their annual energy
12 outlook that we used to look at their gasoline demand
13 forecast to make with ours when we did an RFS2 calculation.
14 So those pairings, if you will, we used for diesel fuel and
15 for gasoline, and we used that portion of the country, which
16 EIA does break out, they have a forecast for individual
17 census districts of the United States, and so we used those
18 trends to apply to a 2008 actual, moving forward through the
19 forecast period of 2030. So that is how we generated those
20 numbers, both in a low demand side, and a high demand side.
21 And that is for total demand in the state, recognizing that
22 not all of the product to Nevada and Arizona is delivered
23 via pipeline. So we started with what we believe is their
24 total demand numbers for 2008.

25 So here they are for Arizona, and you will see

1 that basically the highlights here are gasoline in the low
2 demand, and once again, this is the EIA low demand case,
3 this is essentially flat, 2020 and 2030, .1 percent
4 increase, .8 percent decrease. So that is essentially flat.
5 In the high demand EIA case, we see much stronger growth,
6 almost 32 percent by 2030. On the, I guess on the diesel
7 side, we see that there is very strong growth, and then you
8 take the grand totals of all the fuels and you will see
9 anywhere from 30 to 54 percent by 2030, either a low or a
10 high case. Now, important to point out that, as we did with
11 the gasoline forecast in California, the gasoline demand
12 forecast for Arizona and Nevada, on the next slide, were
13 adjusted downward to compensate for the Renewable Fuel
14 Standard Part 2, and that is resulting in increased amounts
15 of E85 in this column, and displacing E10 gasoline on sort
16 of an energy equivalent basis, moving forward over the
17 forecast period. So same thing here -- more E85 than
18 currently is going on, a lot more in Arizona than in Nevada,
19 and a bit dampening of the gasoline demand forecast. And as
20 is the case with California, we have assumed an E10 cap on
21 the low level blends, recognizing that certainly Arizona and
22 Nevada may have some opportunity to go to an E15 blend that
23 California does not have over the near and mid-term, but for
24 purposes of analysis, we assumed an E10. If there was an
25 E15 cap for low level blends, then the number of the E85

1 blends would be smaller than they are in this forecast.

2 Nevada is very similar. The numbers are a little
3 bit higher because, once again, we are using the same -- or,
4 excuse me, the percent increases are a bit higher, they are
5 not identical, because actually the jet fuel demand growth
6 in Nevada is greater, growing at a greater rate than that of
7 Arizona.

8 So now, how does all of this play out with
9 additional pipeline exports? Once again, for the low case,
10 we are seeing that there is an actual decline in gasoline
11 exports to the neighboring states, both Arizona and Nevada,
12 but we are seeing overall an increase because of the diesel
13 and the jet fuel of anywhere between 37 and 22 percent over
14 the forecast period. So still growth, so this is sort of a
15 total demand pull on California source product, or product
16 moved into and through California. High case, significantly
17 higher, doubling basically by 2030 for Arizona, and 41
18 percent increase for Nevada. So we are still showing growth
19 in the pipeline sourced from California, and this is -- bare
20 in mind, we are assuming that the pipeline exports from the
21 East because Arizona has that flexibility, get it from the
22 west, get it from the east, we are assuming the east
23 pipeline shipments take priority, meaning they fill that
24 system up first, which is assumed it is 2015, and then
25 operate that capacity and then continue to use the spare

1 pumping capacity in the west line up through the forecast
2 period.

3 So do we see using these assumptions and these
4 growth rate assumptions and analyses, do we see constraints
5 in these pipeline systems? And the answer is essentially
6 no, not over the forecast period. That is because demand
7 has come off so much and now the new, latest forecast in
8 this IEPR cycle, are a lot less than they were in the last
9 IEPR cycle two years ago. The one exception here to be
10 noted is in the pipeline system, Colton to Las Vegas, the
11 CalNev System, we are showing that there would be a bump up
12 to a capacity limit in 2021 in the high case, and 2026 in
13 the low case, but that is easily addressed since Kinder
14 Morgan already has a project essentially approved that they
15 have now deferred moving forward by spending capital and
16 actually instituting the construction, because they do see a
17 drop in demand, and no reason to do that. Now, take it a
18 step further, if in fact the pipeline project scenario I
19 mentioned coming out of Utah is actually constructed, then
20 this kind of expansion of the Colton to Las Vegas system
21 would not be necessary because there will be additional
22 capacity out of Utah -- assuming there is supply.

23 So refinery operations, as I mentioned, that is
24 part of our analysis, we assume, yes, there is some
25 continuing growth in the amount of crude oil processed at

1 the refineries. That is their processing capacity. How
2 much crude oil will actually run through their refineries
3 will never be at 100 percent because they have to do
4 maintenance on these crude units, so it will be some level
5 less than 100 percent utilization rate of that capacity, and
6 we are seeing that the capacity numbers have come down
7 recently. There have been some heavier than normal crude
8 oil maintenance work and there has also been, you know, a
9 running of the refineries a little bit less, lower
10 utilization rates, because the margins were poor at times.
11 And, yes, that is more like 2007, not 2008 for decent
12 gasoline time, so we understand that. But there has been a
13 recent trend of a sort of downward utilization rate. But we
14 are assuming a utilization rate of almost 90 percent over
15 the entire forecast period. Now, when you process
16 additional barrels of crude oil, we assume that the ratio of
17 products you are making at the refinery from those
18 additional barrels of crude oil being processed would be
19 similar to what they were in 2008. We clearly recognize
20 that refiners have the capability to adjust some of these
21 ratios of either distillate, or jet fuel, or even some of
22 the gas in how they blend some of the gassing components, so
23 they would have different ratios than those presented here.
24 But for the sake of our analysis, we are assuming that these
25 ratios are held constant throughout the forecast period. So

1 any time we see more crude oil, we will get more products
2 available for use in California, as well as export, in these
3 ratios.

4 Now, I want to point out, as I did in my initial
5 presentation today, this chart is slightly different than
6 the one that is in the report, and this is the correct chart
7 that we will be using in the revised document. I just want
8 to point out that these numbers are a little bit different
9 than what you saw in the actual staff document. So looking
10 at a low import case, we go, how do you minimize additional
11 imports? Well, one assumption is that the growth rate for
12 additional crude oil processing is not the low import case,
13 produce more products, do not have to import as much, and a
14 low demand case. So the purpose of this analysis is to
15 bracket the amount of import growth to a low side and a high
16 side, and as you will see soon, the bracketing actually
17 results in an increase in exports, and I will talk about
18 that. So we only have one scenario of refinery creep, and
19 that is in the low import case, and we have no refinery
20 creep, or level distillation capacity in the high import
21 case. This is the same that we did for crude oil
22 assessment.

23 So as you will see in just a moment and in this
24 bullet, the low import case actually results in California
25 exporting 250,000 barrels per day, by 2015, of gasoline.

1 Now, you might say that is a lot and, yes, it is, it is
2 about a quarter of what we use now, so we would turn into a
3 very large exporting hub, something like the European
4 refining community. So we do not think that is going to
5 happen, this is just an artifact of how we have set up this
6 analysis and we will show you why we do not think that will
7 happen, and what they will do. So we think there is
8 something that they can do, and one of them is eliminating
9 gasoline blend stock imports, another is actually reducing
10 the amount of partially processed crude oil, or unfinished
11 oil that they obtain from outside the refinery, and they
12 help make a lot of their refineries to produce additional
13 gasoline, and some diesel fuel, without processing anymore
14 crude oil, so they do today.

15 This complex set of charts, and yes, I do not have
16 as many pretty pictures as last time, these are more tables,
17 but that is how we have set it up. This is showing you the
18 initial numbers and you are seeing that these were basically
19 sort of the net imports in 2008, 51,000 barrels a day on
20 average of gasoline. We were a net exporter of diesel fuel,
21 we were long in diesel fuel and it was being exported over
22 the dock. Jet fuel, we were a slight net exporter, we were
23 usually a large importer, but jet fuel demand was down
24 significantly. So total, basically a net exporter over the
25 marine docks. Now, net change is rather dramatic for

1 gasoline, net importer to a very very large net exporter,
2 do not think that is going to happen. High import case
3 looks a bit more reasonable, you get into slight less
4 imports by 2015, but then into a net exporter. So once
5 again, would the refineries continue processing as much
6 crude oil, or even increasing that, and having more and more
7 excess product to export? No. We do not think they would
8 do that. So the first change is you eliminate those imports
9 of gassing components, and so you change the impact so you
10 are not as much in balance in gasoline, and you fix the
11 imbalance in 2020 in the high case. Same thing, you just
12 take it a step further, you go, "Well, I'm not going to
13 purchase unfinished oils and stick them in my fluidized
14 catalytic cracking unit, I'm going to not do that," and then
15 I reduce the gasoline imbalance further, actually
16 eliminating it in 2015, and still having a very large
17 imbalance by 2020 and 2025.

18 So, I guess the short story is that, unlike two
19 years ago, we were showing continued growth in California
20 demand on all fuels and its subsequent growth in imports;
21 now, because of the very low gasoline demand outlook, we are
22 seeing an imbalance develop in the refining sector that we
23 do not think will stand, we think they will make some
24 adjustments. The final adjustment to make, of course, would
25 be the closure of some refinery assets, or even the

1 reduction in the amount of crude oil being processed, or
2 their utilization rate not being 90 percent, but maybe being
3 85 percent, 80 percent. And that change would reduce the
4 demand for crude oil imports. And we have not looked at
5 that because these two changes are only adjusting gasoline
6 blending stocks and unfinished oils, not crude oil. But
7 that would be a third change to make.

8 Just to touch on that pipeline from the Salt Lake
9 City refining complex up here, this is a pipeline that goes
10 all the way to the North Las Vegas suburbs, that would be
11 designed to bring in 62,000 barrels a day of petroleum
12 products as early as next fall. The pipeline capacity has
13 an upper limit of 118,000 barrels per day and, once again,
14 both of these assume there has to be incremental supply
15 available to move from the Salt Lake City area, down to
16 North Las Vegas. But that kind of pipeline actually being
17 constructed and coming online would dramatically reduce the
18 amount of products coming into Las Vegas, the west, at least
19 to have the ability to reduce them. Obviously, there would
20 be a competition between that pipeline system and the west
21 line, and Las Vegas would like to see that kind of
22 competition, I am sure.

23 So how does that scenario change the imbalance?
24 Well, it makes it worse, obviously, because more product
25 available in California because now it is being displaced on

1 a product coming from Salt Lake City. So these imbalance
2 numbers become very large, so there will be even more excess
3 supply in California according to this forecast. In the
4 high demand case, a bit of total -- become a big of a net
5 exporter in the region versus a net importer in the high
6 case. And then we remove that assumption that, "Oh, yeah,
7 the refineries will process a little bit more crude oil,"
8 there is not any refinery creep in either the low or the
9 high case, and so this only impacts the low case estimate --
10 low import case estimate -- and we see a reduction from
11 these numbers, down to these lower bars down here. So,
12 almost 140,000 barrels a day less of an imbalance by 2025.
13 So one final note on this slide, we did not look at any
14 refinery expansion projects, an old Chevron Richmond project
15 that recently ran into some EIR difficulties with their
16 project there, they had a hydro cracker, I guess,
17 replacement essentially that was going to increase gasoline
18 production by 7 percent, they have made statements that they
19 are not going to move forward with that project because of
20 the downward decline in demand. So we do not think there
21 are any other refinery projects that we are aware of to
22 increase local supply at this time, and that is likely
23 because of some poor economics, as well as near term trends
24 of downward demand. And that concludes my presentation. I
25 would be happy to take any questions.

1 COMMISSIONER BYRON: Commissioner Boyd, not
2 having served with you on the Transportation Committee for
3 more than a couple years now, what a change.

4 VICE CHAIR BOYD: Yes.

5 COMMISSIONER BYRON: Some dramatic changes as a
6 result of the downturn in the economy, and new pipelines
7 being built, it is not quite the same picture we saw two
8 years ago.

9 VICE CHAIR BOYD: No. I agree with you. I do not
10 have any other comments on this presentation.

11 COMMISSIONER BYRON: Nor do I, Mr. Schremp. Thank
12 you very much.

13 MR. SCHREMP: Thank you for your time.

14 MR. EGGERS: Good afternoon, Commissioners. My
15 name is Ryan Eggers. I am an Energy Commission specialist
16 in the Fossil Fuels Office. I am here today to present the
17 staff import crude oil forecast.

18 To jump right in, California refineries import
19 crude oil to make up the difference between California's own
20 domestic production and the inputs needed to satisfy the
21 demand for their products. As seen in this figure, U.S.
22 crude oil production has been on the decline since 1986.
23 From 1986, when U.S. crude oil production peaked, until
24 2008, California crude oil production has declined 41
25 percent, Alaskan crude oil production has declined 61

1 percent, and the rest of the United States has declined 36
2 percent. This represents a 57 percent decline in U.S. crude
3 oil production as a whole over that same time period.

4 Looking more specifically at California crude oil
5 production, California has for the most part gotten its
6 crude oil from onshore sources. These sources, the top five
7 producing oil fields in 2008, were all in Kern County.
8 Offshore production peaked in 1995 and most of that offshore
9 production occurred off the Santa Barbara County coast. And
10 more long-term perspective of California crude oil
11 production shows that California has been producing oil
12 since the mid-1800s. During that time, it peaked in 1985 at
13 424 million barrels and has steadily declined ever since.
14 On a more interesting note, if you sum up all the production
15 of California crude oil from the mid 1980s until today, it
16 would only sum up to about 93 percent of global oil demand
17 in 2008.

18 Here are some of the current trends in crude oil
19 production for 2008, namely global crude oil production was
20 31.7 billion barrels in 2008; U.S. crude oil production was
21 1.8 billion barrels in 2008, which was only 5.7 percent of
22 global production; California crude oil production in 2008
23 was 239 million barrels, this represented 13 percent of U.S.
24 production, but was only three-quarters of 1 percent of
25 global production.

1 Staff would also like to note that the decline
2 in crude oil production for California, just demonstrated in
3 the previous slide, is expected to continue into the future,
4 as well as U.S. declines, most notably in Alaska.

5 Because of these declines in crude oil production,
6 imports in crude oils have steadily increased to fill in the
7 production gap. As seen here from the early 1800s to the
8 mid-1990s, Alaska provided the bulk of import crude oil to
9 California refineries. Since the mid-1990s, foreign crude
10 oil has become an increasing portion of the import crude oil
11 portfolio, and has become the majority since the early
12 2000s. To put more specific numbers on these trends, total
13 imports in crude oil have increased 24 percent since 1998 to
14 2008, imports of Alaskan crude oil has declined 60 percent
15 during that same time period, and because of that, foreign
16 crude oil imports have picked up the slack by increasing at
17 a rate of 11.7 percent a year. With those increases,
18 foreign imports of crude oil are three times larger than
19 their 1998 amounts. So, using these trends previously
20 demonstrated, we hope to flesh out the outlook for imported
21 crude oil in California to 2030.

22 The approach used by staff in order to calculate
23 future import values was pretty simple in its conception.
24 First, we make a forecast on the refinery distillation
25 capacity to 2030, then we also make a forecast for the

1 California crude oil production side, taking the
2 difference between these two forecasts gives us a crude
3 import forecast value, which we can then make infrastructure
4 requirement calculations based on.

5 This slide displays the staff forecasts for crude
6 oil imports to California refineries. These forecasts
7 assume that all 20 California refineries will be operating
8 at a utilization rate of 89.9 percent of maximum capacity
9 throughout the forecast. I would also like to note that
10 these input forecasts assume the recently closed Bakersfield
11 Refinery will be open by January of 2011, and no new
12 refineries will be opened. By assuming these two
13 constraints, the general increase in refinery capacity known
14 as "refinery creep" becomes the difference between the two
15 forecasts. In the high refinery case, we assume a refinery
16 creep value of .45 percent, and in the low refinery input
17 forecast, we assumed no refinery creep. Of note, the
18 difference between these two lines in 2030 will be 68.9
19 million barrels.

20 On the California crude oil production side,
21 recent declines in crude oil production has led staff to
22 forecast two declining production forecasts. In the high
23 decline scenario, we assume a 3.2 percent per year decline
24 in crude oil production. This value was arrived at as a 10-
25 year average of the historic decline in crude oil production

1 for California. In the low production decline scenario,
2 we assume a declining rate of 2.2 percent per year, this was
3 the most recent three-year trend within crude oil
4 production.

5 By putting these four lines together, namely the
6 high refinery input forecast with the high production
7 decline scenario, and the low refinery input forecast with
8 the low production decline scenario, yields are high and low
9 import forecasts. Here is the low crude oil forecast, along
10 with historic numbers for refinery inputs and crude oil
11 production. Using the low refinery input forecast and the
12 low production decline scenario, staff finds that crude oil
13 imports will grow from the 2008 level of 406 million barrels
14 to 440 million barrels by 2015. Under this forecast,
15 imports will continue to increase to 461 million barrels by
16 2020, and 497 million barrels by 2030.

17 In the high California crude oil import forecast,
18 which uses the high refinery input forecast and the high
19 production decline scenario, staff finds that imports will
20 grow to 476 million barrels by 2015 to 519 million barrels
21 by 2020, and to 596 million barrels by 2030. It should also
22 be noted that these relatively small changes in both
23 refinery input and crude oil production will result in
24 higher import. Crude oil forecasts require almost 100
25 million more barrels than the lower forecasts.

1 To recap, staff believes that crude oil imports
2 will continue to increase to 2030. This increase is
3 primarily a result of declining California crude oil
4 production and in the high import forecasts, increases in
5 refinery capability. The low import forecast uses a
6 production decline rate of 2.2 percent per year with no
7 expansion in refinery capability. This produces an increase
8 in crude oil imports of 22 percent by 2030. In the case of
9 the high import forecast, it uses a production decline rate
10 of 3.2 percent with expansion of refinery capacity occurring
11 at a rate of .45 percent a year. This forecast yields an
12 increase of imports of 47 percent by 2030.

13 Using the two increasing import forecasts, staff
14 has then calculated the additional yearly tanker visits that
15 will be necessary to meet additional crude oil import needs.
16 Seeing the figure on the slide, staff assumes that both the
17 cargo capacity of both VLCC and Aframax vessels will remain
18 constant over the forecast period. These values are shown
19 by the bars on this graph. Additional tanker visits are
20 indicated by the ship icons on the figure. The low forecast
21 for additional tanker visits is produced by using the
22 incremental crude oil import figures from the low import
23 forecast, and dividing it by the VLCC cargo capacity. This
24 low forecast has an additional 17 tanker visits per year by
25 2015, and an increase of an additional 46 visits by 2030.

1 For the high additional tanker visit forecast, the
2 incremental crude oil import figures from the high import
3 forecast was used, and was then divided by the Aframax cargo
4 capacity. This forecast estimates an additional 100 visits
5 per year by 2015, and an estimated 272 visits per year by
6 2030.

7 Giving the staff forecast of increasing crude oil
8 imports and increased tanker visits, additional storage tank
9 capacity for marine facilities serving the oil tankers will
10 be necessary. Staff first assumes that the existing storage
11 infrastructure is near or at maximum capacity, therefore, by
12 using the incremental crude oil figures from the low and
13 high import forecasts, two separate cycling rates were
14 applied to those figures to calculate the low and high
15 estimate. For the low estimate, a one million barrels of
16 storage per 23 million barrels of imports was used. This
17 type of throughput is similar to that estimated for the
18 proposed Berth 408 Project. It is applied to the low
19 increment of oil import figures. The second cycling rate is
20 a 1 million barrel per 12 million barrels of imports and
21 assumes that the new infrastructure will be working at a
22 rate roughly half that to the Berth 408 Project. This
23 cycling rate was then applied to the high incremental crude
24 oil figures to generate the high storage tank estimate.
25 Using these methodologies, staff expects additional storage

1 tank capacity to range between 2.4 to 9.5 million barrels
2 by 2020, and to 4 to 15.9 million barrels by 2030. Staff
3 also estimates that the majority of these facilities, about
4 60 percent, will have to be built in Southern California to
5 accommodate this need.

6 As in all forecasts, there are many uncertainties
7 that can alter their outcomes. Here are two items that
8 staff deemed were most relevant to the discussion, the first
9 being, can crude oil production decline be halted, or even
10 reversed due to technology advances or expanded access to
11 offshore reserves. From a resource perspective, the answer
12 is yes, there are offshore resources which I will talk about
13 in the next three slides. Also, technology is always
14 improving, which lowers the price of retaining resources
15 that are currently economically unavailable, which could
16 alter the forecasts, but these advances are hardly steady or
17 predictable phenomenon. Next, will new crude oil import
18 facilities be completed in time to maintain the inadequate
19 supply of crude oil to California refineries? The Berth 408
20 Project is expected to relieve most of the near term needs
21 of marine infrastructure, but there are no new projects that
22 can account for the forecasted long-term infrastructure
23 needs.

24 With regards to California crude oil production,
25 the first item I would like to talk about is the possible

1 expansion of crude oil production in federal outer
2 Continental Shelf waters, or OCS waters. On October 1st of
3 2008, Congress took no action to reinstate the moratoria on
4 drilling in these waters. This opened up the possibility of
5 increased crude oil production off the California coast.
6 MMS has estimated that there are 5.8 to 15.8 billion barrels
7 of undiscovered technically recoverable resources existing
8 off the California shore, of which half are in federal OCS
9 waters. They have estimated that between 53 to 73 percent
10 of those are economically recoverable under a crude oil
11 price ranging from \$16 per barrel to \$160 per barrel. This
12 said, development of these areas cannot occur until a five-
13 year program and a planning for specific sale process has
14 been carried out and approved. These processes combined can
15 take 3.5 to 5 years to complete. Absent any complications
16 including litigation and other complications, EIA estimates
17 indicate it could take even 10 years. Assuming that the
18 moratoria is lifted, staff then used Department of Energy
19 estimates of the new crude oil production coming from these
20 areas. The DOE forecasts presented here and in our staff
21 report assumes that production from the moratoria areas will
22 begin in 2015. Seventy-four percent of the total increased
23 production from these areas is forecasted to originate in
24 California OCS waters. While a significant amount of crude
25 oil could be produced from these fields, with the forecast

1 in crude oil field decline rates from existing fields, the
2 new OCS oil production is likely only to offset those
3 declines. Even under the low incremental import forecasts,
4 imports could only be shrunk by 36 million barrels a year by
5 2020 from their 2008 totals. Under the high import
6 forecast, crude oil imports would rise by only 37 million
7 barrels by 2030, but not as drastically as the status quo
8 scenario in the high import forecast of 191 million barrels.

9 Given that any federal OCS project would not be in
10 effect any time soon, there is only one project that staff
11 knows that could increase short-term production. This is
12 the Tranquillon Ridge Project, which is a Plains Exploration
13 and Production Company Project that involves drilling of
14 additional wells from Platform Irene, off the Santa Barbara
15 Coast. It has the potential to begin generating additional
16 crude oil within one year of approval and estimated to
17 reduce 2.9 to 9.9 million barrels a year until the sunset of
18 operations in 2024. But currently, as far as staff knows,
19 the status of this project is in doubt, given its failure to
20 win California State Assembly approval last July. This
21 concludes my presentation. Are there any questions or
22 comments?

23 VICE CHAIR BOYD: Well, first, I would say it was
24 a very good analysis, however, well, enough said. But the
25 however goes to assumptions and uncertainties that you

1 correctly identified. I, for one, question the likelihood
2 after slaving away here with some of you for seven and a
3 half years of trying to get additional storage capacity in
4 California, and secondly, venturing out into the California
5 OCS is an interesting experiment, and there is a history in
6 this state that goes way beyond my years here, it goes back
7 to the spill that Mr. Sparano referenced this morning, and
8 that is tough territory to get into, so if I was planning
9 California's future, which I guess we are in a way, I am
10 kind of skeptical about us getting at that resource, but it
11 is a very interesting analysis. As others have said, there
12 is a lot of interesting and good analytical data in what you
13 have done today. Anyway, those are just thoughts, no
14 comment necessary.

15 COMMISSIONER BYRON: Mr. Eggers, if I may, I want
16 to make sure I understand the forecasts that you are doing,
17 the low forecast, high forecast, I am looking back at slides
18 11 and 12, for instance --

19 MR. EGGERS: Perfect.

20 COMMISSIONER BYRON: I hope I am not showing my
21 ignorance of this question, but do these factor in the Low
22 Carbon Fuel Standard and/or the Renewable Fuel Standard 2
23 requirements into these forecasts?

24 MR. EGGERS: No. These forecasts only take into
25 account keeping current California refineries operating at

1 the 98.9 percent, so regardless of what is happening on
2 the demand side, we are assuming that California refineries
3 will be operating at the same rate into the future.

4 COMMISSIONER BYRON: But you have one problem, if
5 you have a rule or a standard like this, do we really care
6 what capacity the refineries are operating at? Wouldn't we
7 rather see the forecasts based upon the implementation of
8 the standard?

9 MR. SCHREMP: Well, if I may, Commissioner Byron,
10 this is Gordon Schrempp, I will just go back to your previous
11 question. Our forecasts for all transportation fuels do
12 account for a Renewable Fuels Standard Part 2, and as I was
13 trying to illustrate in my previous work, we believe that
14 results in a large imbalance that can be corrected by the
15 refineries not importing blend stocks for gasoline, and then
16 not using as much unfinished oil, such that they have
17 addressed the RFS2 and neighboring state needs, and the
18 total downturn in California's gasoline demand, without
19 adjusting these crude oil input numbers or forecasts. To
20 take it a step further and actually say they will run at
21 lower crude oil rates because of maybe some other potential
22 implications of the Low Carbon Fuel Standard, even backing
23 out more gasoline, that is certainly possible, and then it
24 would start to affect these forecasts. I think the crude
25 oil forecasts that staff has worked on have incorporated the

1 impacts of the RFS2 such that they do not appreciably
2 impact crude oil import forecasts as we have analyzed. We
3 would have to go a step even further than that, and that is
4 to reduce the crude oil they are operating in refineries
5 from some impacts of the Low Carbon Fuel Standard that we
6 have not yet portrayed because of the level of uncertainty
7 associated with that regulation.

8 COMMISSIONER BYRON: Well, I am not going to waste
9 everybody's time, but I am not sure I am following you
10 there, Mr. Schremp, so we are going to have to discuss this
11 some more.

12 MR. SCHREMP: Okay.

13 COMMISSIONER BYRON: Let me ask you, on slide 14,
14 these low and high forecasts and the additional tanker
15 visits, is there any consideration of whether or not the
16 ports are going to be able to handle anywhere from 50 to 250
17 additional visits per year in 2030?

18 MR. EGGERS: Gordon?

19 MR. SCHREMP: We do not anticipate a problem
20 handling this increased -- we are not handling them, we are
21 not Stevedores or Harbor Pilots, but the industry and the
22 complex to handle these vessels should be sufficient,
23 keeping in mind that the ports are multi-use, and the lion's
24 share of the vessel activity, or potential congestion is
25 from the cargo container vessels. A massive amount of cargo

1 container vessels ply these waters, especially Port of Los
2 Angeles, Port of Long Beach, so as a fraction of vessel
3 activity, if you will, the petroleum base, both crude oil
4 and petroleum products, is a much smaller subset. So, yes,
5 these even on the high side, say one additional vessel visit
6 per day, yes, that is a lot more than today, but in the
7 grand scheme of total vessel visits, it should be handled,
8 and a secondary point is that they are designed to go to a
9 specific destination within the port, especially in Southern
10 California, a new berth, so a new space for them to actually
11 tie up to, that would be Berth 408 -- if that does get
12 approved.

13 COMMISSIONER BYRON: Okay.

14 VICE CHAIR BOYD: I do have a question and it
15 relates to Alaska, and for years everybody talks about in
16 documents the import of crude oil in decline, and it is
17 pretty generally presumed by most that the North Slope is in
18 decline. And I have no -- well, I was going to say I have
19 no basis to challenge that, yet I found it interesting this
20 past spring to have a lengthy discussion with a major North
21 Slope operator, who talked about their plans to invest an
22 incredible amount of money in the North Slope, in terms of
23 the facilities are old and need a lot of R&R and what have
24 you, and that they are planning on operating up there for at
25 least 50 more years, and I did ask the obvious, "You mean

1 there is oil to be had?" And they feel, yes. So --

2 COMMISSIONER BYRON: There is money to be had.

3 VICE CHAIR BOYD: Well, yeah, I just do not know
4 if they are presuming \$140 barrel oil, or we will pay for
5 that investment, or what. I thought it a curious situation.
6 And I do not know if that is a question or not. I do not
7 know if you have any different data, or information, or an
8 answer to why people would be wanting to do that, unless --
9 kind of like pumping that heavy crude out of California, it
10 just keeps coming even though it is theoretically almost
11 exhausted some times of the year.

12 MR. SCHREMP: Commissioner Boyd, I think you are
13 right, there have been some real recent changes in Alaska
14 production, the decline rate does seem to have slowed a
15 little bit, there has been more activity and there are more
16 plans. Certainly, \$140 crude oil does merit additional
17 plans being brought to Management about what one can do up
18 there, and so, yes, that is not a surprise. So, sure, the
19 decline rate in Alaska could be slowed, even arrested. That
20 is a possible. But I think for purposes of our additional
21 imports of crude oil, it has no impact whatsoever because we
22 are looking at water borne imports of crude oil, so I guess
23 we are in different -- because if it is coming from Alaska,
24 or Saudi Arabia, it does not matter, it is coming in a
25 marine vessel. And there is some merit to the size of the

1 marine vessel and how many additional trips, whether it is
2 a very large crude carrier of VLCC or an Aframax vessel, so
3 there can be some incremental vessel visits that could
4 change if we see Alaska crude oil being around a lot longer
5 than maybe we anticipate. But for all intents and purposes,
6 it will not change the volume metric increase in crude oil
7 that would be necessary because of California's continuing
8 crude oil decline.

9 VICE CHAIR BOYD: And presuming the California
10 demand for finished product, thus crude oil, goes where you
11 project it to go. Okay, thank you.

12 COMMISSIONER BYRON: Thanks, Mr. Eggers.

13 MS. GREEN: Commissioners, that concludes our
14 staff and stakeholder presentations. We can now move on to
15 the public comment session if you wish.

16 COMMISSIONER BYRON: All right. Mr. Eggers gets
17 credit for keeping us on time. I do not have any blue
18 cards, so I think what we will do is we will just solicit
19 comments and questions at this time. We will start with
20 those that took all the trouble to be here today.

21 MR. PAGE: We do have one request to speak from
22 Michael Redeemer.

23 COMMISSIONER BYRON: Michael Redeemer?

24 VICE CHAIR BOYD: Michael Redeemer.

25 MR. PAGE: Oh, I am sorry.

1 COMMISSIONER BYRON: Who is not here.

2 VICE CHAIR BOYD: Who is not here.

3 MR. BRAEUTIGAN: Should we wait?

4 VICE CHAIR BOYD: If you have a question, ask it
5 while we wait, before we turn to the phone.

6 COMMISSIONER BYRON: Please identify yourself.

7 MR. BRAEUTIGAN: My name is John Braeutigan. I
8 work for Valero Energy Corporation. I had a couple
9 questions and some comments. To save time for responding to
10 my questions, maybe the staff could just view them as
11 information requests. I had -- they did a great job, first
12 of all, of putting out a lot of data. The questions are
13 more on the projections of VMT coming along where they
14 showed the historical data. This is mainly for the gasoline
15 demand, and the diesel demand, and somewhat for the jet, if
16 we could see what numbers were then used in the forecasts
17 going forward for the base VMT or like the freight they are
18 saying -- freight traffic has dropped off in the Los Angeles
19 Harbor, that would be useful. The other one was,
20 apparently, my understanding, the 2007 base case, they then
21 took a plus X percent demand, I forget the number, and a
22 minus X percent demand. We could argue or have our own
23 theory, we would take an econometric model, hopefully,
24 knowing the price elasticity of the fuels, which nobody
25 knows exactly, you could give a realistic spread of prices

1 and have a realistic spread of demand, but what would
2 really be important would be to know the exact assumptions
3 in that base case to 2007. For instance, whether -- and
4 apparently -- the RFS2 meeting that obligation is not in
5 there, and whether what assumptions were in there for future
6 vehicle efficiency -- was Pavley in there? Was Pavley 2 not
7 in there? Just because, if you are going to start doing
8 things which Gordon did, which was great, saying, "Okay, the
9 RFS2 compliance was not in a base case, let's add that in
10 and see what happens," obviously you do not want to add in
11 something twice. So it would be nice to know exactly what
12 is in there for the assumptions of future policy decisions
13 like vehicle miles because of Pavley, or federal. For the -
14 - I would be curious to know what the staff was looking at,
15 at the magnitude of shift between gasoline and diesel,
16 refineries are limited as to how much they can shift. And
17 then just two comments, one on the blend wall -- please
18 remember, there are two blend walls and each are multi-
19 layered. If you look at the gasoline blend wall, you have
20 the 10 percent limit because of sub-sim for the U.S., or the
21 CARB model, that is your first layer, your second layer is
22 the warranty issue, both original equipment manufacturers
23 and extended warranty companies. The third layer is just
24 having the vehicles, depending on the result of whether
25 warranties are extended or not, having newer vehicles that

1 could handle a higher Ethanol level, and then the fourth
2 layer is funding the infrastructure at the retail level, how
3 do you ever get that accomplished, and getting around,
4 obviously, the Catch 22 situation between the last two. The
5 same layers are really there on the diesel side, too, where
6 Gordon did a great job pointing out where we are not really
7 sure how you are going to get all that E85. If you look at
8 the curves, just the number of vehicles required, I would
9 question, is that really -- what he pointed out was good
10 data, that is what is required -- begs the question, is it
11 really achievable? You know, does common sense say we
12 really can ramp up that fast? Same thing for diesel,
13 though. There is a B5 blend wall because of the warranty
14 issue. You do not have the sub-sim, you do not have the
15 CARB, but you still have all the other layers of the
16 gasoline blend wall actually operating on a diesel, too, and
17 if you have the Low Carbon Fuel Standard saying, "We want 10
18 percent in diesel, 10 percent in gasoline, and a B5 keeps
19 you from obtaining 10 percent in diesel, that means you have
20 got to get even more in gasoline and now your scenario
21 starts to become even more -- maybe less probable. I have
22 been working in this industry for 30 years, I have never
23 seen a time when there was so much uncertainty. And staff
24 has done a good job. It is really hard to predict. It may
25 be nice to see a couple additional scenarios where you are

1 looking at like the EIA has taken and said, "We do not
2 think the RFS2 can be implemented at the schedule laid out,"
3 and they had a lower amount of cellulosic Ethanol going in,
4 based on their assumptions of how fast cellulosic biofuel
5 would come into the pool, that maybe you could call that
6 common sense or a more likely case, but those are my
7 comments. And the data requests, I will write them down and
8 pass them on to the staff. That would be helpful to have a
9 little bit more background. Thank you.

10 COMMISSIONER BYRON: Thank you. And before you
11 come up, I was just looking to see if staff would respond to
12 any of these. I tend to agree with the first comment that I
13 heard, and that was the inclusion of a lot of the
14 assumptions that were used in the report, VMT and the
15 assumptions in the base case, and whether or not it includes
16 the various standards and Pavley. So you may not want to
17 address it here today -- or, no, I would appreciate it, Mr.
18 Schremp, if you could -- how much of that is in the report
19 and how much could be added?

20 MR. SCHREMP: So, again, the base case that was
21 used, what was referred to as the base case, I think, really
22 was the low case from 2007, the low demand case. We used
23 not the exact case in and of itself, we used the growth
24 rates associated with that case. So we really do not have a
25 set of VMT numbers that would be associated with that. At

1 the same time, that case in 2007 did include Pavley 1, and
2 it did include a Zev mandate as part of the assumptions that
3 were associated with it. So you are correct, it did not
4 have Pavley 2 assumptions in there, and it did not talk
5 about Low Carbon Fuel Standard, or any other items that we
6 talked about today, RFS2. But Pavley 1 should have been
7 included in that case. And the prices, fuel price
8 assumptions are fairly consistent with what we are seeing in
9 our current high price, or low price case assumptions.

10 COMMISSIONER BYRON: Okay, thank you. Our next
11 public comments -- please introduce yourself.

12 MR. REDEEMER: Commissioner Byron, Vice Chairman
13 Boyd, my name is Michael Redeemer. I am the President of
14 Community Fuels, we are a biodiesel manufacturer, you had to
15 hear from somebody in that industry today, right? We are
16 located at the Port of Stockton and, in 2007, we built --
17 permitted and built a biodiesel plant, completed it in mid-
18 2008, brought it up into operation late 2008, and we are
19 currently producing biodiesel and selling it throughout
20 Northern California. I wanted to make a couple comments,
21 they are not prepared, but I will submit written comments.
22 I wanted to reinforce the comments that Mr. Schremp made
23 about infrastructures being a limitation. I can speak from
24 personal experience. We sell our fuel through the existing
25 distribution network, we work with fuel distributors. And

1 we have heard many times from them that one of the issues
2 they have is they do not have a tank to store biodiesel at
3 their facility, and they are reluctant to make the
4 investment to put that tank in place until there is a
5 market in their area for biodiesel. So I am hoping that
6 this is one of the areas the AB 118 funds could help support
7 because I think there is a real need, and we are not talking
8 500,000 gallon tanks, we are talking 10,000 to 20,000 gallon
9 tanks, so it is a pretty simple thing, but there is a real
10 chicken and the egg issue that we are confronted out there
11 day in and day out, so I just wanted to reinforce the
12 comment that there are infrastructure issues that are a
13 limitation. The other comment I will make is the diesel
14 demand forecast for biodiesel 20 years out, at 57 million
15 gallons per year does not inspire a great deal of confidence
16 in our investors. And I do not know if that is something
17 that could be revisited, but at our facility alone, we have
18 the capability of expanding to over 60 million gallons per
19 year, and so to look at a future market that is only 57
20 million gallons, I think, is a little troubling. And I
21 would point out that, with the new CAFÉ standards kicking
22 in, and the fact that there has been a 5.6 percent growth
23 rate in light duty diesel since 2001, I think you could look
24 at a scenario where existing diesel technology, which has
25 been out there for a long time with the right after

1 treatment, combined with the fueling infrastructure, you
2 could see a diesel alternative scenario for reducing fuel
3 demand. Diesels are 30 percent more efficient than gasoline
4 vehicles. So I would really encourage you to take a look at
5 the impact of these CAFÉ standards and the availability now
6 of light duty diesels that can be sold in California, and
7 see if there is another reality out there that we could at
8 least hypothetically say exists. That is all my comments.
9 I look forward to working with you and your staff and I
10 appreciate the opportunity to address you today.

11 VICE CHAIR BOYD: Thanks, Michael.

12 MR. REDEEMER: Any questions?

13 VICE CHAIR BOYD: A couple comments. The
14 biodiesel demand estimate, yeah, we will take a good look at
15 that. The light-duty diesel and CAFÉ and the potential
16 demand from light duty diesel -- for light duty diesels in
17 California, and thus the fuel demand, is something we have
18 talked about ad nauseum here, and amongst sister agencies
19 just because, while factually you are right in terms of
20 their characteristics and their capabilities, there remains
21 this overriding issue of the unpopularity of light duty
22 diesels heretofore with the California consuming public. So
23 I guess we have looked, we will look, we will continue to
24 look, and maybe the forthcoming generation will have a
25 different view of the potential light duty diesels. And we,

1 too, are just watching the market, our citizens of
2 California responding to the capabilities of this
3 technology, or not. It is a good point, but I do not think
4 our crystal ball is any better than yours at the moment.

5 COMMISSIONER BYRON: In fact, I would have to add,
6 the staff does a very good job making these forecasts,
7 putting a lot of data forward, but would you really want to
8 base your business plan on a government forecast?

9 MR. REDEEMER: Well --

10 COMMISSIONER BYRON: And so your investors should
11 certainly be looking at other factors, and other scenarios,
12 as well, as to what they are going to make their investment
13 decisions on.

14 MR. REDEEMER: Well, they certainly do, but I do
15 think it is important since it is sort of -- I think the
16 Energy Commission is viewed as a competent expert in this
17 area, that your scenarios are one of those factors, as are
18 the regulations that California adopts. I mean, a lot of
19 the renewable fuels and biodiesel infrastructure is, as we
20 have heard, based on the RFS2 regulations. And so we are
21 all making our decisions based on the world as we see it
22 going into the future. And this is just one datapoint, but
23 I would have to say, 57 million gallons sounds a little
24 light to me, just -- I do not know, but I would be happy to
25 talk to your staff about other scenarios.

1 COMMISSIONER BYRON: We would welcome that. And
2 Mr. Schremp is up there and hopefully he is not going to
3 defend his forecast, that what he is going to do is talk
4 about why he has not included the scenario you are
5 discussing, then.

6 MR. REDEEMER: Thank you.

7 MR. SCHREMP: Well, I was going to fall on the
8 sword over that 57 million until I lost -- it seems like I
9 lost you support about telling Michael to ignore our
10 forecast!

11 COMMISSIONER BYRON: At least with regard to
12 making business decisions, do not use this forecast.

13 MR. SCHREMP: Well, actually, Michael, I mean,
14 that is a good point, but I think we do not really have what
15 I would say as bodies of forecasts at this point, we have a
16 reaction to what we think is a minimum RFS2 requirement for
17 biodiesel. I clearly acknowledge that that is eminently
18 doable today, is no supply challenge, but does have some
19 infrastructure issues as you reiterated. We are awaiting
20 some additional pathway information on the Low Carbon Fuel
21 Standard. We believe that, to reduce the carbon intensity
22 of diesel fuel analogous to that of gasoline, you will have
23 to use some lower carbon material. Biodiesels of some sort
24 probably have lower carbon intensities than the base diesel.
25 So we expect to see that probably at least B10, if not even

1 B20, or beyond, as a necessity to achieve compliance with
2 the Low Carbon Fuel Standard. So biodiesel demand in
3 California, minimum requirement levels, are not going to be
4 driven by RFS2 unless Congress changes those targets
5 appreciably. But we believe there will be significant
6 demand increases from the Low Carbon Fuel Standard, we just
7 have not been able to perform said analysis yet, until those
8 additional pathways and carbon intensities information
9 becomes available. If that happens soon, enough time to
10 modify -- include in our modified final document, we will do
11 so, and then maybe you will have a little bit better
12 information, but it is possible this may be continuing work
13 into next year, as more information becomes available on the
14 biodiesel side. But you are right, yeah, it is a pretty low
15 number.

16 COMMISSIONER BYRON: Sir, please come forward and
17 identify yourself.

18 MR. WASON: Yeah, my name is Bill Wason, I am with
19 an organization called Sustainable Bio-Brazil, and I also
20 work with U.S. NGO CO₂ Start. My comments today are directed
21 at how quickly markets can shift if you have certain factors
22 in play. I think one of the most important factors is you
23 have a meeting coming up in Copenhagen and you have an IPCC
24 Report that will come out a year and a half from now. It
25 could change dramatically what the assumptions are of the

1 risks associated with climate change. I think you also
2 have pretty savvy sectors in the private side, looking at
3 these shifts and how quickly they can occur, and what the
4 opportunity is in relation to marketing of low carbon fuels.
5 You have a Low Carbon Fuels Standard that requires a 1
6 percent reduction per year and a certain RFS standard that
7 assumes biofuel or low carbon fuel introduction on that
8 basis. But the experience in Brazil is really useful to
9 understand. For I do not know how long, they said fully
10 flexed fuel vehicles were no good and did not exist, and the
11 minute that a car company came in with price dip parity,
12 fully flexed vehicle, every car now, minus a few gasoline,
13 you know, super cars, is fully flex fuel and every fuel
14 station has Ethanol, and 80 percent of the sales there on
15 new cars are Ethanol. So I think the same thing could
16 happen in the California market if you defined dynamics and
17 created alliances with the right partners. And I do not
18 think the limitations that you see now, there is a
19 limitation of 5 percent biodiesel, although that Reg is
20 changing to 20 percent, there is already a process, ASTM, in
21 place to do that. In addition, they are not mentioning that
22 renewable diesel technology is already here, and it is going
23 to come into play, and could be blended with biodiesel or
24 sold as a separate component. There is a lot of room for
25 you to look at how you do your avoided deforestation and red

1 planning process in terms of your own state, and how that
2 could lead to both carbon credits on the industry side and,
3 more important, feed stock on the oil side for biodiesel or
4 renewable diesel, or renewable jet fuel, and how that could
5 interplay, as well, with how you deal with indirect land use
6 issues and come up with integrated strategies. We are
7 working and going to present to some of the people at the
8 California Summit an integrated strategy with some of the
9 Governors in Brazil, particularly the Governor of Maranhao,
10 who has a lot of decision-making with some of the other
11 Governors. I think the opportunity is to say, "Where are we
12 going to get large volumes of feedstock on liquid fuels that
13 will deal with a bridge, and how do we work with some of the
14 changes that are occurring in the market?" You have Fiat
15 buying Chrysler -- Fiat is the leading producer of cars in
16 Brazil. Fiat is eager to see partnerships that create the
17 kind of progressive thinking so that they can bring in a
18 whole new generation of turbo diesels that are common in
19 Europe, but not in the market here. Those turbo diesels are
20 a whole lot more exciting if you have a tree planting
21 program and you have an oil seed that is sustainable, and
22 you end up with 100 percent renewable turbo diesel. You are
23 not even depending on diesel. And there, you can introduce
24 the 16 mile per gallon car and it will sell. So that is the
25 kind of thinking that you need to be at to shift beyond the

1 paradigm of what is in your predictions. Your predictions
2 are valid, but are not going to work in a very carbon
3 constrained world that you may be looking at, as soon as
4 2011 IPCC Report. And I think that is the way to look at
5 the problem, think out the problem, create the partnerships,
6 and you can derail those partnerships real easily if you
7 say, "Oh, indirect land use changed, there is no carbon
8 benefits from this feedstock or that feedstock, or this
9 conversion process, and we do not have any answers and we
10 can't do anything." And I think it is easy to do that
11 because there are other pressures getting you to do that,
12 and I think you are in a perfect position to look outside
13 the box and come up with integrated strategies that work.

14 COMMISSIONER BYRON: Very good, thank you. I hope
15 you will provide some written comments for this Commission,
16 as well. Thank you.

17 MR. WASON: Thank you. Anyone else wish to make a
18 public comment here in the audience? If not, we will turn
19 to WebEx.

20 MR. JANUSCH: Seth Jacobsen, are you on the line?

21 MR. JACOBSEN: Hello.

22 MR. JANUSCH: Go ahead.

23 COMMISSIONER BYRON: Please identify yourself and
24 ask your question, or comment.

25 MR. JANUSCH: Hi, this is Seth Jacobsen from the

1 Center for Advanced Studies on Terrorism. First of all, I
2 just want to say hi to Gordon and the rest of the staff, and
3 to thank them for an outstanding analysis and report. I
4 have a quick question and it addresses the notion that all
5 supplying countries are not created equal in terms of crude
6 oil for California. And I wanted to ask whether staff would
7 please add a section to the report that simply describes
8 which countries supply crude oil to California, quantifies
9 and ranks these countries as sources of imports, and
10 describes the past trends and future projections for which
11 countries may supply California with crude oil to meet
12 staff's forecasts.

13 COMMISSIONER BYRON: So, first of all, do we have
14 that information, Mr. Schremp?

15 MR. SCHREMP: This is Gordon Schremp. Yes,
16 Commissioner Byron, we have a list of crude oil imports by
17 source country that we can certainly provide in the
18 document, that we revise. Seth, just to be clear, you are
19 also talking about a forward look as to what sources
20 additional crude oil imports may originate from. Is that
21 correct?

22 MR. JACOBSEN: If possible. We have seen that
23 analysis. If staff is comfortable with the analyses that
24 industry has done, to include that, or reference it. If
25 not, then the trends themselves might be used.

1 MR. SCHREMP: Well, Seth, I think at minimum we
2 can tap into some of the information that has already been
3 provided as part of the IEPR process. Baker & O'Brien has
4 looked at source countries, or source regions for this
5 incremental crude coming to California. And, you know,
6 staff, we have not done our own analysis in this arena, and
7 Baker and O'Brien does have a great deal of expertise in
8 this area, so staff does not have a problem referencing some
9 information already part of the IEPR process, or even
10 including some of that information in the Appendix in the
11 revised report. So we can do both historical sources of
12 crude oil coming to California by source, as well as some
13 projections by like Baker & O'Brien. We would be happy to
14 do that.

15 MR. JACOBSEN: Great. Thank you.

16 MR. SCHREMP: You are welcome.

17 COMMISSIONER BYRON: Good. Thank you, Mr.
18 Jacobsen, another good comment. Do we have anyone else on
19 WebEx?

20 MR. JANUSCH: Well, we are going to open the lines
21 up and if anyone has a comment, speak now, or forever hold
22 your peace.

23 COMMISSIONER BYRON: All right, everyone out on
24 WebEx, you are now off mute. So we are hearing some things
25 that I do not think people expect us to be hearing. Is

1 there anyone out there who would like to ask a question?

2 If so, now is the time. All right, you can re-mute them.

3 All right, staff, well done. I think we are at the close

4 here, then. I would like to thank everyone for being here.

5 Commissioner Boyd, would you like to make some closing

6 comments?

7 VICE CHAIR BOYD: Thank you, I would. Again, I

8 would say thanks to staff for, as a lot of people said, an

9 extremely thorough and interesting analysis. But I think,

10 as has been evident by some of the comments and testimony

11 today, I think when we get to finally doing what we have to

12 do for the IEPR, which is getting closer all the time, I do

13 think we have to be a little more comprehensive in terms of

14 the fuels. Early on, I got a little concerned that we were

15 heavy on liquid fuels, but not all of them, and no

16 discussion of gas use fuels, including biogas, and

17 electricity, but Felix came up and rescued the day on that

18 point. And so I think we have to make sure that we reach in

19 all directions and do as comprehensive a view as we can take

20 on all the subject areas. Diesel is an area I particularly

21 want to comment on because, rightfully or wrongfully, I have

22 felt for some time now that diesel is a major worldwide

23 problem. Now, at the moment, at the pump, you would not

24 believe it because we are back down to seeing diesel prices

25 here in this country below -- at or below -- regular

1 gasoline again, when for a long time they were above. I
2 think that is an artifact of the recession, the worldwide
3 recession. And I feel that when we get back on our feet and
4 economic demand returns worldwide, and then the forces of
5 industry go back to work, that diesel is going to be a
6 problem. So I am very keen on biodiesel and renewable
7 diesels as something that we need to be thinking about in
8 order to meet the demands of the diesel cycle engine for
9 fuel, it does not have to be petroleum-based, necessarily,
10 either. So I think we will talk more about that internally
11 as we work on this. And one of the last, Mr. Wason, I
12 believe, talked about an integrated strategy, I think we are
13 into that. I do not believe he is here anymore. He came
14 late and left early, so he missed a lot of discussion of the
15 day, and would have picked up more on fully flexed vehicles,
16 which was another one of his subjects. And one of the
17 points I wanted to make, I made it earlier today, is that,
18 you know, for years we have all known the auto companies
19 were going to build a flexible fuel vehicle for practically
20 nothing more than what we would call an "ordinary vehicle."
21 And they do, to get their CAFÉ credits. But what we have
22 lacked is a fueling infrastructure and a lot of talk today
23 about the potential for significant increase in the E85
24 fuel, but I am very personally skeptical about us being able
25 to supply that fuel because we are a democracy, not a

1 dictatorship, and the fueling infrastructure has been very
2 slow to respond, and I am kind of skeptical as to whether we
3 will see the day. I think we need it. There are vehicles
4 that are capable of using it, but we will have to talk about
5 that more as we finalize our recommendations and report. I
6 did not comment this morning when Mr. Sparano made reference
7 to carbon capture and storage and CO₂ for oil recovery, and I
8 should have.

9 COMMISSIONER BYRON: And nuclear.

10 VICE CHAIR BOYD: Well, I was not going to touch
11 nuclear. It is not a transportation fuel, directly. It
12 just makes electricity, and that becomes a transportation....
13 But the use of CO₂ for enhanced oil recovery has long been
14 done and is well known, but the use of enhanced over cover
15 as carbon capture and sequestration is a little bit
16 different. Heretofore, CO₂ has been used to force oil out of
17 the ground, and with not a lot of thought to whether CO₂
18 stays there in perpetuity, and so this agency, as you know,
19 is deep into carbon capture and storage research and
20 development, and no pun intended, and still one of the
21 unanswered things is, you know, there are very well known
22 places to put CO₂ such as in saline aquifers or exhausted
23 natural gas reservoirs, that have proven themselves. That
24 is another thing to talk about, oil reservoirs as being a
25 place to permanently store CO₂, so that is going to become a

1 case by case analysis some day in the future, so we just
2 do not leap into CO₂ enhanced over recovery as a carbon
3 offset or a carbon capture and storage. On the other hand,
4 it may be better to inject CO₂ even if some does get out, as
5 long as they can quantify it, then burn valuable natural gas
6 to make steam to stick in the ground. So there may be
7 trade-offs someday, but I do not think we have to venture
8 into that, necessarily, in this particular analysis. But I
9 think we need some discussion internally more about covering
10 the total fuels waterfront and talking a little about the
11 what if scenarios, you know, what if some of these policies
12 do not come to fruition? Or, what if they come to fruition,
13 but the feeling is they cannot be accomplished? What is the
14 alternative strategy that we ought to think about to provide
15 whatever, a form of transportation fuel, to fuel the
16 transportation sector? And this today has been very heavy
17 on conventional petroleum, and I have a concern about, well,
18 what if those projections cannot be realized because you
19 cannot build the infrastructure in question, or you cannot
20 meet the other goals and objectives, climate change, or what
21 have you, that have been played out. And we better be in a
22 position to say what aggressive actions need to be taken in
23 other areas to address that total transportation fuel
24 demand. But I found today very interesting, and it is
25 obvious from the comments of those who were here earlier, or

1 toughed it out for the rest of the day, that this has been
2 a very thorough job in analyzing certain questions. So I
3 appreciate the work that they have done. Enough said.

4 COMMISSIONER BYRON: Thank you, Commissioner. I
5 was also very impressed with today's workshop. I found it
6 to be very informative and the staff got lots of compliments
7 today from the oil industry, as well as the alternative
8 fuels sources. So, congratulations. I would like to add
9 mine. I thought it was an excellent report and very good
10 presentations. I would also like to give my thanks to the
11 stakeholders for their presentations, and the commenters at
12 the end were also very helpful. I was reminded, looking
13 back at the workshop notice, that we are very interested in
14 your written comments, and the due date for them, I believe,
15 is September 4th. I will let the staff correct me if I have
16 that -- okay, the nods are indicating that is correct. I,
17 too, like Commissioner Boyd, thought for a while this
18 workshop was misnamed -- I thought maybe it was supposed to
19 be "The Liquid Transportation Fuel Forecast and Analysis."
20 I was glad that we did hear from Mr. Oduyemi from Southern
21 California Edison, and that we got into some of the
22 alternative renewable fuels, as well. I am reminded of the
23 loading order on the electric side of the energy equation
24 and Commissioner Boyd was involved in promulgating that a
25 long time ago. We want to use less, first, go after the

1 renewables fuels second, because they really do transform
2 the industry, and renewables by definition are sustainable,
3 instead of depleting all the fossil fuels over the course of
4 time. And I do not mean, as Mr. Sparano indicated earlier,
5 that we are going to run out of oil, but we know that we are
6 depleting fields and constantly looking for new ones. But
7 the loading order is use less, renewables, and then fossil.
8 And I think that applies here, as well. I am reminded, as
9 well from a comment that one of our commenters made towards
10 the end, who has worked in this industry for a long time, he
11 has never seen so much uncertainty as he sees now, and I
12 think that is a concern. To the extent that is true, you
13 know, the staff has done a very good job with the
14 information and the data available to them, and there are
15 many possible futures here that we are trying to consider.
16 The markets will shift, the laws will change, and customers
17 will respond unexpectedly. And that is what I meant earlier
18 by my comment about making business decisions based upon
19 these forecasts. We certainly look towards industry and
20 entrepreneurs that are willing to take ventures into areas
21 that we may not see or understand completely at this point.
22 So I think we have got plenty of good information here
23 today. I look forward to the responses to the comments that
24 we get from the public on this report. Commissioner Boyd, I
25 think we have got a lot of information here to make some

1 good recommendations around transportation or fuels in
2 this year's IEPR. With that, I would like to thank
3 everybody and we are adjourned.

4 (Whereupon, at 4:18 p.m., the workshop was adjourned.)

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way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand
this _____ day of August, 2009.

Peter Petty